Application: 09-09-013
(U 39 G)
Exhibit No.:
Date: April 23, 2010
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2011 GAS TRANSMISSION AND STORAGE RATE CASE

ERRATA TO PREPARED TESTIMONY

DATED SEPTEMBER 18, 2009

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 1: **Introduction and Policy**
Witness: **Steven A. Whelan**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
1-2	Table 1-1, Line 1	2013	260.1	260.4
1-2	Table 1-1, Line 1	2014	263.7	264.6
1-2	Table 1-1, Line 2	2013	235.3	235.1
1-2	Table 1-1, Line 2	2014	252.7	251.8
1-3	Table 1-2, Line 1	2011	0.277	0.271
1-3	Table 1-2, Line 1	2012	0.297	0.287
1-3	Table 1-2, Line 1	2013	0.320	0.308
1-3	Table 1-2, Line 1	2014	0.326	0.313
1-3	Table 1-2, Line 2	2011	0.333	0.338
1-3	Table 1-2, Line 2	2012	0.347	0.357
1-3	Table 1-2, Line 2	2013	0.361	0.374
1-3	Table 1-2, Line 2	2014	0.357	0.372
1-3	Table 1-2, Line 2	CAGR	3	4
1-3	Table 1-2, Line 3	2011	0.277	0.271
1-3	Table 1-2, Line 3	2012	0.297	0.287
1-3	Table 1-2, Line 3	2013	0.320	0.308
1-3	Table 1-2, Line 3	2014	0.326	0.313
1-3	Table 1-2, Line 3	CAGR	20	19
1-3	Table 1-2, Line 4	2011	0.333	0.338

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
1-3	Table 1-2, Line 4	2012	0.347	0.357
1-3	Table 1-2, Line 4	2013	0.361	0.374
1-3	Table 1-2, Line 4	2014	0.357	0.372
1-3	Table 1-2, Line 4	CAGR	5	6
1-3	Table 1-2, Line 6	2011	0.195	0.207
1-3	Table 1-2, Line 6	2012	0.188	0.207
1-3	Table 1-2, Line 6	2013	0.178	0.200
1-3	Table 1-2, Line 6	2014	0.168	0.195
1-3	Table 1-2, Line 6	CAGR	-5	-2
1-3	Table 1-2, Line 7	2014	0.548	0.546
1-3	Table 1-2, Line 8	2014	0.273	0.272
1-3	Table 1-2, Line 9	2013	0.134	0.135

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 2: **PG&E's Gas Transmission Facilities and Services**
Witness: **Roger Graham**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
2-2	15		backbone	N/A
2-4	1		2,066	2,049
2-4	Table 2-1, Line 1	Firm Receipt Point Capacity (MMcf/d)	1,034	1,025
2-4	Table 2-1, Line 1	Firm Delivery Point Capacity (Mdth/d)	1,042	1,033
2-4	Table 2-1, Line 2	Firm Receipt Point Capacity (MMcf/d)	1,016	1,008
2-4	Table 2-1, Line 2	Firm Delivery Point Capacity (Mdth/d)	1,024	1,015
2-4	Table 2-1, Line 3	Firm Receipt Point Capacity (MMcf/d)	2,050	2,033
2-4	Table 2-1, Line 3	Firm Delivery Point Capacity (Mdth/d)	2,066	2,049
2-4	Table 2-1, Line 5	Firm Receipt Point Capacity (MMcf/d)	43.1	42.8
2-4	Table 2-1, Line 5	Firm Delivery Point Capacity (Mdth/d)	43.7	43.4

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
2-6	8-9		The average firm delivery point capacity of the southern system, also know as the Baja Path, is 1, 068 MDth/d as show in Table 2-1.	N/A
2-6	10		N/A	currently
2-8	22		1,070	1,068
2-9	8		1,070	1,068
2-16	15		422	417
2-16	32		2,066	2,049
2-16	33		44	43
2-17	1		1,406	1,390
2-17	3		1112	1,096
2-17	12		557	541
2-19	30		only $0.0013	less than $0.001

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 3: **PG&E's Gas Storage Facilities and Services**
Witness: **Roger Graham**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
3-8	13-15		The capacities in Table 3-4 do not include PG&E's portion of the Gill Ranch Gas Storage project.	N/A

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 5: **Operating and Maintenance Expenses**
Witness: **Frank W. Maxwell**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
5-3	1-2		System Average Percent	SAP
5-6	20		2011	2008

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 6: **Capital Expenditures**
Witnesses: **Rick C. Brown**
Roy A. Surges

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
6-2	Table 6-1, Line 1	2009	112.3	112.1
6-2	Table 6-1, Line 1	2010	97.6	97.4
6-2	Table 6-1, Line 1	2012	128.1	128.0
6-2	Table 6-1, Line 1	2013	130.5	130.4
6-2	Table 6-1, Line 1	2014	103.9	103.7
6-2	Table 6-1, Line 1	Total 2011-2014	478.6	478.2
6-2	Table 6-1, Line 2	2010	104.4	103.9
6-2	Table 6-1, Line 2	2011	60.1	52.3
6-2	Table 6-1, Line 2	2012	49.8	52.2
6-2	Table 6-1, Line 2	2013	45.9	47.0
6-2	Table 6-1, Line 2	Total 2011-2014	214.2	210.1
6-2	Table 6-1, Line 3	2010	24.7	25.2
6-2	Table 6-1, Line 3	2011	46.6	54.4
6-2	Table 6-1, Line 3	2012	61.3	58.9
6-2	Table 6-1, Line 3	2013	32.7	31.4
6-2	Table 6-1, Line 3	Total 2011-2014	156.8	160.9
6-2	Table 6-1, Line 4	2009	1.2	1.1
6-2	Table 6-1, Line 5	2009	226.7	226.4
6-2	Table 6-1, Line 5	2010	228.3	228.1

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
6-2	Table 6-1, Line 5	2012	240.1	240.0
6-2	Table 6-1, Line 5	2013	209.9	209.8
6-2	Table 6-1, Line 5	2014	179.7	179.5
6-2	Table 6-1, Line 5	Total 2011-2014	853.6	853.2
6-2	4		843.9	853.2
6-2	5		211.0	213.3
6-2	6		2011	2007
6-2	7		185.0	125.0
6-2	7		40	35
6-2	8		to 36 inch diameter	and greater
6-2	11		126.0	120.4
6-2	12		37	36
6-2	16		63	64
6-3	Table 6-2, Line 1	2009	19.6	19.5
6-3	Table 6-2, Line 3	2013	8.9	8.8
6-3	Table 6-2, Line 3	2014	9.2	9.1
6-3	Table 6-2, Line 3	Total 2011-2014	35.0	34.8
6-3	Table 6-2, Line 4	2010	4.2	4.1
6-3	Table 6-2, Line 5	2012	59.6	59.5
6-3	Table 6-2, Line 5	2014	34.3	34.2
6-3	Table 6-2, Line 5	Total 2011-2014	181.3	181.1
6-3	Table 6-2, Line 6	2010	3.4	3.3
6-3	Table 6-2, Line 7	2009	1.8	1.7
6-3	Table 6-2, Line 8	2009	112.3	112.1
6-3	Table 6-2, Line 8	2010	97.6	97.4
6-3	Table 6-2, Line 8	2012	128.1	128.0
6-3	Table 6-2, Line 8	2013	130.5	130.4
6-3	Table 6-2, Line 8	2014	103.9	103.7
6-3	Table 6-2, Line 8	Total 2011-2014	478.6	478.2

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
6-6	Table 6-5, Line 1	2009	19.6	19.5
6-6	Table 6-6, Line 1	2009	12.4	17.3
6-6	Table 6-6, Line 1	2010	17.6	20.0
6-6	Table 6-6, Line 1	2011	11.6	12.0
6-6	Table 6-6, Line 1	Total 2011-2014	114.1	114.5
6-6	Table 6-6, Line 2	2009	3.1	3.2
6-6	Table 6-6, Line 3	2009	(0.3)	(0.7)
6-6	Table 6-6, Line 3	2010	1.0	0.8
6-6	Table 6-6, Line 4	2009	7.7	3.1
6-6	Table 6-6, Lien 4	2010	2.7	0.5
6-6	Table 6-6, Line 4	2011	0.4	-
6-6	Table 6-6, Line 4	Table 2011-2014	0.4	-
6-9	29		7.9	7.3
6-9	31		33.6	27.8
6-10	1		2011	2010
6-10	1		8	13.9
6-10	3		35.1	37.7
6-10	5		13.4	7.4
6-10	23		7.7	3.1
6-10	23		2010	2009
6-11	Table 6-7, Line 1	2013	8.9	8.8
6-11	Table 6-7, Line 1	2014	9.2	9.1
6-11	Table 6-7, Line 1	Total 2011-2014	35.0	34.8
6-12	Table 6-8, Line 1	2010	4.2	4.1
6-14	Table 6-9, Line 1	2012	59.6	59.5
6-14	Table 6-9, Line 1	2013	58.8	58.9
6-14	Table 6-9, Line 1	2014	34.3	34.2
6-14	Table 6-9, Line 1	Total 2011-2014	181.3	181.1
6-16	23		51.0	51.1

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
6-17	Table 6-10, Line 1	2010	3.4	3.3
6-18	17		34.0	35.0
6-18	20		26.0	27.0
6-19	Table 6-11, Line 1	2009	1.8	1.7
6-19	Table 6-12, Line 1	2009	11.4	13.6
6-19	Table 6-12, Line 1	2010	17.5	13.2
6-19	Table 6-12, Line 1	2011	12.0	10.8
6-19	Table 6-12, Line 1	2013	6.7	7.9
6-19	Table 6-12, Line 3	2009	6.8	2.5
6-19	Table 6-12, Line 3	2010	6.7	7.4
6-19	Table 6-12, Line 4	2009	36.1	38.2
6-19	Table 6-12, Line 4	2010	60.5	63.6
6-19	Table 6-12, Line 4	2011	30.4	23.8
6-19	Table 6-12, Line 4	2012	28.0	30.4
6-19	Table 6-12, Line 4	2013	22.6	22.7
6-19	Table 6-12, Line 4	Total 2011-2014	99.2	95.1
6-19	Table 6-12, Line 5	2010	104.4	103.9
6-19	Table 6-12, Line 5	2011	60.1	52.3
6-19	Table 6-12, Line 5	2012	49.8	52.2
6-19	Table 6-12, Line 5	2013	45.7	47.0
6-19	Table 6-12, Line 5	Total 2011-2014	214.2	210.1
6-19	13		204.5	210.1
6-19	14		51.1	52.5
6-19	12		2.7	2.5
6-19	15		2011	2013
6-20	15		8.0	8.2
6-20	31		77.4	75.9
6-23	12		62.0	58.4
6-23	Table 6-13, Line 1	2010	24.7	25.2

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
6-23	Table 6-13, Line 1	2011	46.6	54.4
6-23	Table 6-13, Line 1	2012	61.3	58.9
6-23	Table 6-13, Line 1	2013	32.7	31.4
6-23	Table 6-13, Line 1	Total 2011-2014	156.8	160.9
6-23	22		17.1	16.6
6-24	8		2015	2014
6-24	33		96.5	95.4
6-25	Table 6-14, Line 1	2009	0.6	0.5
6-25	Table 6-15, Line 3	2009	1.2	1.1

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 8: **Results of Operations**
Witness: **Rosemary L. Green**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-2	Table 8-1, Line 1	2011	529,926	529,928
8-2	Table 8-1, Line 1	2012	561,289	561,292
8-2	Table 8-1, Line 1	2013	591,888	591,892
8-2	Table 8-1, Line 1	2014	613,895	613,904
8-2	Table 8-1, Line 4	2011	529,080	529,082
8-2	Table 8-1, Line 4	2012	561,457	561,460
8-2	Table 8-1, Line 4	2013	592,232	592,236
8-2	Table 8-1, Line 4	2014	614,780	614,789
8-2	Table 8-2, Line 6	($000s)	70,277	74,000
8-2	Table 8-2, Line 7	($000s)	26,779	23,056
8-2	Table 8-2, Line 13	($000s)	529,926	529,928
8-3	Table 8-3, Line 2	2014	68,748	68,747
8-3	Table 8-3, Line 5	2012	219,661	219,660
8-3	Table 8-3, Line 5	2013	235,426	235, 244
8-3	Table 8-3, Line 5	2014	252,844	251,995
8-3	Table 8-3, Line 6	2012	68,014	74,186
8-3	Table 8-3, Line 6	2013	64,296	71,619
8-3	Table 8-3, Line 6	2014	60,685	69,864
8-3	Table 8-3, Line 7	2012	31,830	25,660

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-3	Table 8-3, Line 7	2013	33,769	26,631
8-3	Table 8-3, Line 7	2014	36,125	27,804
8-3	Table 8-3, Line 13	2012	561,289	561,292
8-3	Table 8-3, Line 13	2013	591,888	591,892
8-3	Table 8-3, Line 13	2014	613,895	613,904
8-22	Table 8-5, Line 1	F	69,585	73,308
8-22	Table 8-5, Line 1	G	26,779	23,056
8-22	Table 8-5, Line 1	M	527,228	527,230
8-22	Table 8-5, Line 3	F	70,277	74,000
8-22	Table 8-5, Line 3	G	26,779	23,056
8-22	Table 8-5, Line 3	M	529,926	529,928
8-22	Table 8-5, Line 10	F	196	206
8-22	Table 8-5, Line 10	G	75	64
8-22	Table 8-5, Line 13	F	670	705
8-22	Table 8-5, Line 13	G	255	220
8-22	Table 8-5, Line 18	F	6,445	6,490
8-22	Table 8-5, Line 18	G	10,071	10,925
8-22	Table 8-5, Line 20	F	5,324	5,318
8-22	Table 8-5, Line 20	G	802	808
8-22	Table 8-5, Line 24	F	2,712	2,812
8-22	Table 8-5, Line 24	G	272	172
8-22	Table 8-5, Line 25	F	8,865	9,719
8-22	Table 8-5, Line 25	G	2,402	1,548
8-22	Table 8-5, Line 25	M	55,962	55,963

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-22	Table 8-5, Line 26	F	17,062	18,011
8-22	Table 8-5, Line 26	G	3,836	2,888
8-22	Table 8-5, Line 26	M	95,577	95,578
8-22	Table 8-5, Line 27	F	21,069	21,608
8-22	Table 8-5, Line 27	G	5,507	4,969
8-22	Table 8-5, Line 30	F	44,576	46,109
8-22	Table 8-5, Line 30	G	20,314	18,782
8-22	Table 8-5, Line 30	M	375,833	375,834
8-22	Table 8-5, Line 31	F	25,701	27,891
8-22	Table 8-5, Line 31	G	6,465	4,274
8-22	Table 8-5, Line 31	M	154,093	154,094
8-22	Table 8-5, Line 32	F	292,383	317,307
8-22	Table 8-5, Line 32	G	73,545	48,628
8-22	Table 8-5, Line 32	M	1,753,053	1,753,060
8-23	Table 8-6, Line 1	F	766,923	767,064
8-23	Table 8-6, Line 1	G	142,272	142,132
8-23	Table 8-6, Line 2	F	0	20,541
8-23	Table 8-6, Line 2	G	42,031	21,496
8-23	Table 8-6, Line 3	F	766,923	787,604
8-23	Table 8-6, Line 3	G	184,303	163,628
8-23	Table 8-6, Line 3	M	3,779,367	3,779,373
8-23	Table 8-6, Line 6	F	(2,149)	(2,134)
8-23	Table 8-6, Line 6	G	531	515
8-23	Table 8-6, Line 7	F	(2,093)	(2,077)

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-23	Table 8-6, Line 7	G	531	515
8-23	Table 8-6, Line 14	F	130,248	130,669
8-23	Table 8-6, Line 14	G	14,442	14,022
8-23	Table 8-6, Line 18	F	130,250	130,670
8-23	Table 8-6, Line 18	G	14,846	14,426
8-23	Table 8-6, Line 19	F	346,809	342,161
8-23	Table 8-6, Line 19	G	96,592	101,239
8-23	Table 8-6, Line 19	M	1,636,641	1,636,640
8-23	Table 8-6, Line 20	F	292,383	317,307
8-23	Table 8-6, Line 20	G	73,545	48,628
8-23	Table 8-6, Line 20	M	1,753,053	1,753,060
8-24	Table 8-7, Line 1	F	70,277	74,000
8-24	Table 8-7, Line 1	G	26,779	23,056
8-24	Table 8-7, Line 1	M	529,926	529,928
8-24	Table 8-7, Line 2	F	6,445	6,490
8-24	Table 8-7, Line 2	G	10,971	10,925
8-24	Table 8-7, Line 5	F	5,486	5,479
8-24	Table 8-7, Line 5	G	1,161	1,168
8-24	Table 8-7, Line 6	F	58,346	62,031
8-24	Table 8-7, Line 6	G	14,647	10,963
8-24	Table 8-7, Line 6	M	325,214	325,215
8-24	Table 8-7, Line 7	F	8,128	8,821
8-24	Table 8-7, Line 7	G	2,045	1,352
8-24	Table 8-7, Line 8	F	(53)	(45)

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-24	Table 8-7, Line 8	G	16	8
8-24	Table 8-7, Line 9	F	(29)	22
8-24	Table 8-7, Line 9	G	(41)	(92)
8-24	Table 8-7, Line 14	F	8,045	8,797
8-24	Table 8-7, Line 14	G	2,132	1,380
8-24	Table 8-7, Line 17	F	14,902	16,566
8-24	Table 8-7, Line 17	G	8,828	7,165
8-24	Table 8-7, Line 17	M	145,153	145,154
8-24	Table 8-7, Line 19	F	0	136
8-24	Table 8-7, Line 19	G	386	250
8-24	Table 8-7, Line 21	F	23,197	25,750
8-24	Table 8-7, Line 21	G	11,394	8,842
8-24	Table 8-7, Line 21	M	202,401	202,402
8-24	Table 8-7, Line 22	F	35,149	36,281
8-24	Table 8-7, Line 22	G	3,253	2,121
8-24	Table 8-7, Line 23	F	3,107	3,207
8-24	Table 8-7, Line 23	G	288	188
8-24	Table 8-7, Line 25	F	3,107	3,207
8-24	Table 8-7, Line 25	G	288	188
8-24	Table 8-7, Line 31	F	2,712	2,812
8-24	Table 8-7, Line 31	G	272	172
8-25	Table 8-7, Line 32	F	4,029	4,011
8-25	Table 8-7, Line 32	G	118	135
8-25	Table 8-7, Line 36	F	3,680	5,528

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-25	Table 8-7, Line 36	G	8,648	6,801
8-25	Table 8-7, Line 36	M	124,598	124,599
8-25	Table 8-7, Line 38	F	0	136
8-25	Table 8-7, Line 38	G	386	250
8-25	Table 8-7, Line 41	F	15,423	18,142
8-25	Table 8-7, Line 41	G	11,383	8,665
8-25	Table 8-7, Line 41	M	193,399	193,400
8-25	Table 8-7, Line 42	F	42,923	43,889
8-25	Table 8-7, Line 42	G	3,263	2,298
8-25	Table 8-7, Line 43	F	15,023	15,361
8-25	Table 8-7, Line 43	G	1,142	804
8-25	Table 8-7, Line 49	F	(5,947)	(5,430)
8-25	Table 8-7, Line 49	G	1,249	733
8-25	Table 8-7, Line 50	F	8,865	9,719
8-25	Table 8-7, Line 50	G	2,402	1,548
8-25	Table 8-7, Line 50	M	55,962	55,963
8-26	Table 8-8, Line 1	E	210,495	219,494
8-26	Table 8-8, Line 1	F	67,322	73,494
8-26	Table 8-8, Line 1	G	31,830	25,660
8-26	Table 8-8, Line 1	M	558,591	558,594
8-26	Table 8-8, Line 3	Description	N/A	Total Operating Revenue
8-26	Table 8-8, Line 3	E	219,661	219,660
8-26	Table 8-8, Line 3	F	68,014	74,186
8-26	Table 8-8, Line 3	G	31,830	25,660

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-26	Table 8-8, Line 3	M	561,289	561,292
8-26	Table 8-8, Line 10	F	189	207
8-26	Table 8-8, Line 10	G	89	71
8-26	Table 8-8, Line 13	F	648	707
8-26	Table 8-8, Line 13	G	303	245
8-26	Table 8-8, Line 18	F	6,572	6,648
8-26	Table 8-8, Line 18	G	11,437	11,361
8-26	Table 8-8, Line 20	E	8,957	8,956
8-26	Table 8-8, Line 20	F	5,324	5,323
8-26	Table 8-8, Line 20	G	815	817
8-26	Table 8-8, Line 24	F	2,554	2,829
8-26	Table 8-8, Line 24	G	602	328
8-26	Table 8-8, Line 24	M	11,257	11,258
8-26	Table 8-8, Line 25	F	8,563	10,071
8-26	Table 8-8, Line 25	G	3,659	2,152
8-26	Table 8-8, Line 26	Description	N/A	Total Taxes
8-26	Table 8-8, Line 26	F	16,609	18,389
8-26	Table 8-8, Line 26	G	5,448	3,669
8-26	Table 8-8, Line 26	M	103,056	103,057
8-26	Table 8-8, Line 27	F	21,069	21,898
8-26	Table 8-8, Line 27	G	6,123	5,294
8-26	Table 8-8, Line 27	M	110,455	110,456
8-26	Table 8-8, Line 30	Description	N/A	Total Operating Expenses
8-26	Table 8-8, Line 30	F	44,250	46,936

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-26	Table 8-8, Line 30	G	23,008	20,324
8-26	Table 8-8, Line 30	M	395,666	395,667
8-26	Table 8-8, Line 31	F	23,764	27,250
8-26	Table 8-8, Line 31	G	8,821	5,337
8-26	Table 8-8, Line 31	M	165,623	165,625
8-26	Table 8-8, Line 32	E	783,880	783,876
8-26	Table 8-8, Line 32	F	270,350	310,014
8-26	Table 8-8, Line 32	G	100,356	60,712
8-26	Table 8-8, Line 32	M	1,884,226	1,884,243
8-27	Table 8-9, Line 1	E	235,259	235,078
8-27	Table 8-9, Line 1	F	63,604	70,927
8-27	Table 8-9, Line 1	G	33,769	26,631
8-27	Table 8-9, Line 1	M	589,190	589,194
8-27	Table 8-9, Line 3	E	235,425	235,244
8-27	Table 8-9, Line 3	F	64,296	71,619
8-27	Table 8-9, Line 3	G	33,769	26,631
8-27	Table 8-9, Line 3	M	591,888	591,892
8-27	Table 8-9, Line 10	E	656	655
8-27	Table 8-9, Line 10	F	179	199
8-27	Table 8-9, Line 10	G	94	74
8-27	Table 8-9, Line 13	E	2,244	2,242
8-27	Table 8-9, Line 13	F	613	683
8-27	Table 8-9, Line 13	G	322	254
8-27	Table 8-9, Line 18	E	74,413	74,410

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-27	Table 8-9, Line 18	F	6,695	6,785
8-27	Table 8-9, Line 18	G	11,892	11,804
8-27	Table 8-9, Line 20	E	9,677	9,657
8-27	Table 8-9, Line 20	F	5,324	5,362
8-27	Table 8-9, Line 20	G	863	845
8-27	Table 8-9, Line 24	F	2,286	2,614
8-27	Table 8-9, Line 24	G	673	345
8-27	Table 8-9, Line 25	E	28,210	28,195
8-27	Table 8-9, Line 25	F	7,557	9,244
8-27	Table 8-9, Line 25	G	3,859	2,187
8-27	Table 8-9, Line 25	M	65,532	65,533
8-27	Table 8-9, Line 26	E	45,010	44,974
8-27	Table 8-9, Line 26	F	15,341	17,394
8-27	Table 8-9, Line 26	G	5,780	3,763
8-27	Table 8-9, Line 26	M	110,035	110,036
8-27	Table 8-9, Line 27	E	40,416	40,381
8-27	Table 8-9, Line 27	F	21,069	21,981
8-27	Table 8-9, Line 27	G	6,243	5,367
8-27	Table 8-9, Line 27	M	116,113	116,114
8-27	Table 8-9, Line 30	E	159,838	159,766
8-27	Table 8-9, Line 30	F	43,104	46,160
8-27	Table 8-9, Line 30	G	23,015	20,933
8-27	Table 8-9, Line 30	M	415,486	415,488
8-27	Table 8-9, Line 31	E	75,587	75,477

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-27	Table 8-9, Line 31	F	21,192	25,459
8-27	Table 8-9, Line 31	G	9,854	5,698
8-27	Table 8-9, Line 31	M	176,402	176,404
8-27	Table 8-9, Line 32	E	859,919	858,674
8-27	Table 8-9, Line 32	F	241,091	289,639
8-27	Table 8-9, Line 32	G	112,102	64,825
8-27	Table 8-9, Line 32	M	2,006,846	2,006,872
8-28	Table 8-10, Line 1	B	68,748	68,747
8-28	Table 8-10, Line 1	E	252,678	251,829
8-28	Table 8-10, Line 1	F	59,993	69,172
8-28	Table 8-10, Line 1	G	36,125	27,804
8-28	Table 8-10, Line 1	M	611,197	611,206
8-28	Table 8-10, Line 3	B	68,748	68,747
8-28	Table 8-10, Line 3	E	252,844	251,995
8-28	Table 8-10, Line 3	F	60,685	69,864
8-28	Table 8-10, Line 3	G	36,125	27,804
8-28	Table 8-10, Line 3	M	613,895	613,904
8-28	Table 8-10, Line 10	E	704	702
8-28	Table 8-10, Line 10	F	169	195
8-28	Table 8-10, Line 10	G	101	77
8-28	Table 8-10, Line 13	E	2,410	2,402
8-28	Table 8-10, Line 13	F	578	666
8-28	Table 8-10, Line 13	G	344	265
8-28	Table 8-10, Line 13	M	5,850	5,851

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-28	Table 8-10, Line 18	E	76,636	76,625
8-28	Table 8-10, Line 18	F	6,794	6,907
8-28	Table 8-10, Line 18	G	12,237	12,135
8-28	Table 8-10, Line 20	E	10,164	10,113
8-28	Table 8-10, Line 20	F	5,324	5,394
8-28	Table 8-10, Line 20	G	870	852
8-28	Table 8-10, Line 20	M	26,681	26,682
8-28	Table 8-10, Line 24	E	5,438	5,409
8-28	Table 8-10, Line 24	F	2,028	2,468
8-28	Table 8-10, Line 24	G	812	401
8-28	Table 8-10, Line 25	E	31,629	31,479
8-28	Table 8-10, Line 25	F	6,630	8,764
8-28	Table 8-10, Line 25	G	4,391	2,408
8-28	Table 8-10, Line 25	M	68,744	68,745
8-28	Table 8-10, Line 26	E	49,823	49,593
8-28	Table 8-10, Line 26	F	14,163	16,807
8-28	Table 8-10, Line 26	G	6,472	4,061
8-28	Table 8-10, Line 26	M	115,002	115,004
8-28	Table 8-10, Line 27	E	43,324	43,178
8-28	Table 8-10, Line 27	F	21,069	22,149
8-28	Table 8-10, Line 27	G	6,392	5,460
8-28	Table 8-10, Line 27	M	120,587	120,588
8-28	Table 8-10, Line 30	E	169,783	169,396
8-28	Table 8-10, Line 30	F	42,025	45,862

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
8-28	Table 8-10, Line 30	G	25,102	21,655
8-28	Table 8-10, Line 30	M	430,291	430,295
8-28	Table 8-10, Line 31	E	83,061	82,599
8-28	Table 8-10, Line 31	F	18,660	24,002
8-28	Table 8-10, Line 31	G	11,023	6,148
8-28	Table 8-10, Line 31	M	183,604	183,609
8-28	Table 8-10, Line 32	B	243,571	243,570
8-28	Table 8-10, Line 32	E	944,949	939,692
8-28	Table 8-10, Line 32	F	212,286	273,059
8-28	Table 8-10, Line 32	G	125,407	69,944
8-28	Table 8-10, Line 32	I	36,479	36,478
8-28	Table 8-10, Line 32	J	291,164	291,163
8-28	Table 8-10, Line 32	M	2,088,784	2,088,836

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 10: **Throughput Forecast**
Witnesses: **Eric Hsu**
Matthew Masters

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
10-3	Table 10-1, Line 2	2012	555	557
10-3	Table 10-1, Line 3	2012	238	239
10-3	Table 10-1, Line 4	2012	217	218
10-3	Table 10-1, Line 8	2012	800	802
10-3	Table 10-1, Line 15	2011	508	509
10-3	Table 10-1, Line 16	2011	1,174	1,175
10-3	Table 10-1, Line 18	2011	1,977	1,978
10-3	Table 10-1, Line 18	2012	2,009	2,011
10-6	12		554	555
10-6	13		0.8	1.2
10-6	13		below	above
10-6	22		2.0	2.1
10-6	30		just under	N/A
10-7	1		1.9	About 2.0
10-7	6		5.0	4.5
10-7	10		2.2	3.0
10-7	22-23		about 1.4 percent above	Virtually consistent compared to
10-8	Table 10-2, Line 2	2012	617	619
10-8	Table 10-2, Line 4	2012	233	234
10-8	Table 10-2, Line 8	2012	879	881
10-8	Table 10-2, Line 15	2011	514	515
10-8	Table 10-2, Line 15	2013	528	529
10-8	Table 10-2, Line 16	2013	1202	1,204

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
10-8	Table 10-2, Line 18	2011	2066	2,067
10-8	Table 10-2, Line 18	2012	2098	2,101
10-8	Table 10-2, Line 18	2013	2099	2,102
10-8	13		one	three
10-9	5		plant	plants
10-9	5		was	were
10-9	6-7		its contract with PG&E allows PG&E to dispatch it	some or all of their generation is dispatchable
10-10	16		500	501

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Chapter 11: **Cost Allocation and Rate Design**
Witness: **Ray Blatter**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11-3	Table 11-1, Line 2	Proposed 2011 Rates	14.052	14.044
11-3	Table 11-1, Line 2	$ Change	0.198	0.190
11-3	Table 11-1, Line 3	Proposed 2011 Rates	12.117	12.109
11-3	Table 11-1, Line 3	$ Change	0.192	0.185
11-3	Table 11-1, Line 3	% Change	1.6	1.5
11-3	Table 11-1, Line 4	Proposed 2011 Rates	9.917	9.910
11-3	Table 11-1, Line 4	$ Change	0.169	0.163
11-3	Table 11-1, Line 5	Proposed 2011 Rates	8.919	8.913
11-3	Table 11-1, Line 5	$ Change	0.162	0.156
11-3	Table 11-1, Line 5	% Change	1.9	1.8
11-3	Table 11-1, Line 6	Proposed 2011 Rates	17.949	17.943
11-3	Table 11-1, Line 6	$ Change	0.084	0.079
11-3	Table 11-1, Line 6	% Change	0.5	0.4
11-3	Table 11-1, Line 9	% Change	2.4	2.3
11-3	Table 11-1, Line 14	Proposed 2011 Rates	1.589	1.559
11-3	Table 11-1, Line 19	% Change	31.1	31.0
11-3	Table 11-1, Line 20	% Change	(15.6%)	(15.5%)
11-9	14		43.7	43.4
11-9	Table 11-3, Line 4	Line 401 Cost Allocators	888	880

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11-9	Table 11-3, Line 5	Line 401 Cost Allocators	980	972
11-10	Table 11-4, Line 1	Line 400/2, Line 401 (non-G-XF), and Line 300/319	169,855	169,461
11-10	Table 11-4, Line 1	Common	49,584	49,585
11-10	Table 11-4, Line 1	Total	219,439	219,046
11-10	Table 11-4, Line 2	G-XF	6,520	6,926
11-10	Table 11-4, Line 2	Total	6,520	6,926
11-10	Table 11-4, Line 3	Line 400/2, Line 401 (non-G-XF), and Line 300/319	4,669	4,657
11-10	Table 11-4, Line 3	Total	8,076	8,064
11-10	Table 11-4, Line 4	Line 400/2, Line 401 (non-G-XF), and Line 300/319	174,524	174,118
11-10	Table 11-4, Line 4	G-XF	6,520	6,926
11-10	Table 11-4, Line 4	Total	234,035	234,036
11-11	Table 11-5, Line 1	Total	105,430	103,267
11-11	Table 11-5, Line 2	Total	114,009	115,778
11-11	Table 11-5, Line 3	Total	6,520	6,926
11-11	Table 11-5, Line 4	Total	8,076	8,064
11-12	Table 11-6, Line 2	2011	0.277	0.271
11-12	Table 11-6, Line 2	2012	0.297	0.287
11-12	Table 11-6, Line 2	2013	0.320	0.308
11-12	Table 11-6, Line 2	2014	0.326	0.313

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11-12	Table 11-6, Line 3	2011	0.277	0.271
11-12	Table 11-6, Line 3	2012	0.297	0.287
11-12	Table 11-6, Line 3	2013	0.320	0.308
11-12	Table 11-6, Line 3	2014	0.326	0.313
11-12	Table 11-6, Line 4	2011	0.333	0.338
11-12	Table 11-6, Line 4	2012	0.347	0.357
11-12	Table 11-6, Line 4	2013	0.361	0.374
11-12	Table 11-6, Line 4	2014	0.357	0.372
11-12	Table 11-6, Line 5	2011	0.333	0.338
11-12	Table 11-6, Line 5	2012	0.347	0.357
11-12	Table 11-6, Line 5	2013	0.361	0.374
11-12	Table 11-6, Line 5	2014	0.357	0.372
11-12	Table 11-6, Line 7	2011	0.195	0.207
11-12	Table 11-6, Line 7	2012	0.188	0.207
11-12	Table 11-6, Line 7	2013	0.178	0.200
11-12	Table 11-6, Line 7	2014	0.168	0.195
11-19	2		0.0013	0.0007
11-19	3-4		N/A	and Core local transmission rates that are $0.008 per Dth higher than they would have otherwise been
11-19	Table 11-9, Line 1	2014	0.548	0.546
11-19	Table 11-9, Line 2	2014	0.273	0.272

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Appendix 11A: **Detailed Rate Tables**
Witness: **Ray Blatter**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-1	Table 11A-1, Line 2	Proposed Rates 1/1/2011	14.052	14.044
11A-1	Table 11A-1, Line 2	$ Change	0.198	0.190
11A-1	Table 11A-1, Line 3	Proposed Rates 1/1/2011	12.117	12.110
11A-1	Table 11A-1, Line 3	$ Change	0.192	0.185
11A-1	Table 11A-1, Line 3	% Change	1.6%	1.5%
11A-1	Table 11A-1, Line 4	Proposed Rates 1/1/2011	9.917	9.910
11A-1	Table 11A-1, Line 4	$ Change	0.169	0.163
11A-1	Table 11A-1, Line 5	Proposed Rates 1/1/2011	8.919	8.913
11A-1	Table 11A-1, Line 5	$ Change	0.162	0.156
11A-1	Table 11A-1, Line 5	% Change	1.9%	1.8%
11A-3	Table 11A-3, Line 16	Res	0.2535	0.251
11A-3	Table 11A-3, Line 16	Small Comm	0.2244	0.222
11A-3	Table 11A-3, Line 16	Large Comm	0.1242	0.123
11A-3	Table 11A-3, Line 16	Uncomp. NGV	0.0780	0.077
11A-3	Table 11A-3, Line 17	Res	0.1106	0.105
11A-3	Table 11A-3, Line 17	Small Comm	0.111	0.105
11A-3	Table 11A-3, Line 17	Large Comm	0.111	0.105

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-3	Table 11A-3, Line 17	Uncomp. NGV	0.111	0.105
11A-3	Table 11A-3, Line 17	Comp. NGV	0.111	0.105
11A-3	Table 11A-3, Line 19	Res	0.9675	0.967
11A-3	Table 11A-3, Line 19	Small Comm	0.8970	0.896
11A-3	Table 11A-3, Line 19	Large Comm	0.6791	0.678
11A-3	Table 11A-3, Line 19	Uncomp. NGV	0.6154	0.615
11A-3	Table 11A-3, Line 19	Comp. NGV	0.6154	0.615
11A-3	Table 11A-3, Line 20	Res	8.4720	8.464
11A-3	Table 11A-3, Line 20	Small Comm	8.359	8.351
11A-3	Table 11A-3, Line 20	Large Comm	7.985	7.978
11A-3	Table 11A-3, Line 20	Uncomp. NGV	7.871	7.864
11A-3	Table 11A-3, Line 20	Comp. NGV	7.793	7.787
11A-3	Table 11A-3, Line 21	Res	14.052	14.044
11A-3	Table 11A-3, Line 21	Small Comm	12.117	12.109
11A-3	Table 11A-3, Line 21	Large Comm	9.917	9.910
11A-3	Table 11A-3, Line 21	Uncomp. NGV	8.919	8.913
11A-3	Table 11A-3, Line 21	Comp. NGV	17.949	17.943
11A-4	Table 11A-4, Line 2	2011	8.195	8.005
11A-4	Table 11A-4, Line 2	2012	9.054	8.738
11A-4	Table 11A-4, Line 2	2013	9.716	9.360
11A-4	Table 11A-4, Line 2	2014	10.017	9.607
11A-4	Table 11A-4, Line 4	2011	0.277	0.271
11A-4	Table 11A-4, Line 4	2012	0.297	0.287
11A-4	Table 11A-4, Line 4	2013	0.320	0.308

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-4	Table 11A-4, Line 4	2014	0.326	0.313
11A-4	Table 11A-4, Line 7	2011	8.195	8.005
11A-4	Table 11A-4, Line 7	2012	9.054	8.738
11A-4	Table 11A-4, Line 7	2013	9.716	9.360
11A-4	Table 11A-4, Line 7	2014	10.017	9.607
11A-4	Table 11A-4, Line 10	2011	0.277	0.271
11A-4	Table 11A-4, Line 10	2012	0.297	0.287
11A-4	Table 11A-4, Line 10	2013	0.320	0.308
11A-4	Table 11A-4, Line 10	2014	0.326	0.313
11A-4	Table 11A-4, Line 12	2011	9.899	10.057
11A-4	Table 11A-4, Line 12	2012	10.613	10.923
11A-4	Table 11A-4, Line 12	2013	11.014	11.387
11A-4	Table 11A-4, Line 12	2014	10.973	11.440
11A-4	Table 11A-4, Line 13	2012	0.007	0.008
11A-4	Table 11A-4, Line 14	2011	0.333	0.338
11A-4	Table 11A-4, Line 14	2012	0.347	0.357
11A-4	Table 11A-4, Line 14	2013	0.361	0.374
11A-4	Table 11A-4, Line 14	2014	0.357	0.372
11A-4	Table 11A-4, Line 17	2011	9.899	10.057
11A-4	Table 11A-4, Line 17	2012	10.613	10.923
11A-4	Table 11A-4, Line 17	2013	11.014	11.387
11A-4	Table 11A-4, Line 17	2014	10.973	11.440
11A-4	Table 11A-4, Line 18	2012	0.007	0.008
11A-4	Table 11A-4, Line 19	2011	0.333	0.338

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-4	Table 11A-4, Line 19	2012	0.347	0.357
11A-4	Table 11A-4, Line 19	2013	0.361	0.374
11A-4	Table 11A-4, Line 19	2014	0.357	0.372
11A-4	Table 11A-4, Line 22	2011	4.417	4.412
11A-4	Table 11A-4, Line 22	2012	4.569	4.562
11A-4	Table 11A-4, Line 22	2013	4.823	4.821
11A-4	Table 11A-4, Line 22	2014	4.868	4.870
11A-5	Table 11A-5, Line 2	2011	5.783	5.727
11A-5	Table 11A-5, Line 2	2012	6.106	6.002
11A-5	Table 11A-5, Line 2	2013	6.498	6.391
11A-5	Table 11A-5, Line 2	2014	6.624	6.498
11A-5	Table 11A-5, Line 3	2011	0.087	0.083
11A-5	Table 11A-5, Line 3	2012	0.096	0.089
11A-5	Table 11A-5, Line 3	2013	0.106	0.098
11A-5	Table 11A-5, Line 3	2014	0.108	0.099
11A-5	Table 11A-5, Line 4	2011	0.277	0.271
11A-5	Table 11A-5, Line 4	2012	0.297	0.287
11A-5	Table 11A-5, Line 4	2013	0.320	0.308
11A-5	Table 11A-5, Line 4	2014	0.326	0.313
11A-5	Table 11A-5, Line 7	2011	5.783	5.727
11A-5	Table 11A-5, Line 7	2012	6.106	6.002
11A-5	Table 11A-5, Line 7	2013	6.498	6.391
11A-5	Table 11A-5, Line 7	2014	6.624	6.498
11A-5	Table 11A-5, Line 8	2011	0.087	0.083

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-5	Table 11A-5, Line 8	2012	0.096	0.089
11A-5	Table 11A-5, Line 8	2013	0.106	0.098
11A-5	Table 11A-5, Line 8	2014	0.108	0.099
11A-5	Table 11A-5, Line 9	2011	0.277	0.271
11A-5	Table 11A-5, Line 9	2012	0.297	0.287
11A-5	Table 11A-5, Line 9	2013	0.320	0.308
11A-5	Table 11A-5, Line 9	2014	0.326	0.313
11A-5	Table 11A-5, Line 12	2011	6.574	6.625
11A-5	Table 11A-5, Line 12	2012	6.894	7.007
11A-5	Table 11A-5, Line 12	2013	7.224	7.357
11A-5	Table 11A-5, Line 12	2014	7.234	7.392
11A-5	Table 11A-5, Line 13	2011	0.117	0.121
11A-5	Table 11A-5, Line 13	2012	0.120	0.127
11A-5	Table 11A-5, Line 13	2013	0.124	0.132
11A-5	Table 11A-5, Line 13	2014	0.119	0.129
11A-5	Table 11A-5, Line 14	2011	0.333	0.338
11A-5	Table 11A-5, Line 14	2012	0.347	0.357
11A-5	Table 11A-5, Line 14	2013	0.361	0.374
11A-5	Table 11A-5, Line 14	2014	0.357	0.372
11A-5	Table 11A-5, Line 17	2011	6.574	6.625
11A-5	Table 11A-5, Line 17	2012	6.894	7.007
11A-5	Table 11A-5, Line 17	2013	7.224	7.357
11A-5	Table 11A-5, Line 17	2014	7.234	7.392
11A-5	Table 11A-5, Line 18	2011	0.117	0.121

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-5	Table 11A-5, Line 18	2012	0.120	0.127
11A-5	Table 11A-5, Line 18	2013	0.124	0.132
11A-5	Table 11A-5, Line 18	2014	0.119	0.129
11A-5	Table 11A-5, Line 19	2011	0.333	0.338
11A-5	Table 11A-5, Line 19	2012	0.347	0.357
11A-5	Table 11A-5, Line 19	2013	0.361	0.374
11A-5	Table 11A-5, Line 19	2014	0.357	0.372
11A-5	Table 11A-5, Line 22	2011	3.051	3.049
11A-5	Table 11A-5, Line 22	2012	3.146	3.144
11A-5	Table 11A-5, Line 22	2013	3.313	3.316
11A-5	Table 11A-5, Line 22	2014	3.364	3.366
11A-6	Table 11A-6, Line 2	2011	9.8344	9.606
11A-6	Table 11A-6, Line 2	2012	10.8644	10.486
11A-6	Table 11A-6, Line 2	2013	11.659	11.232
11A-6	Table 11A-6, Line 2	2014	12.0201	11.529
11A-6	Table 11A-6, Line 3	2011	0.0094	0.009
11A-6	Table 11A-6, Line 3	2012	0.0094	0.009
11A-6	Table 11A-6, Line 3	2013	0.0095	0.010
11A-6	Table 11A-6, Line 3	2014	0.0096	0.010
11A-6	Table 11A-6, Line 4	2011	0.3327	0.326
11A-6	Table 11A-6, Line 4	2012	0.35604	0.344
11A-6	Table 11A-6, Line 4	2013	0.3834	0.370
11A-6	Table 11A-6, Line 4	2014	0.39127	0.376
11A-6	Table 11A-6, Line 7	GA IV 2010	11.0784	11.078

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-6	Table 11A-6, Line 7	2011	9.8344	9.606
11A-6	Table 11A-6, Line 7	2012	10.8644	10.486
11A-6	Table 11A-6, Line 7	2013	11.659	11.232
11A-6	Table 11A-6, Line 7	2014	12.0201	11.529
11A-6	Table 11A-6, Line 8	GA IV 2010	0.0183	0.018
11A-6	Table 11A-6, Line 8	2011	0.0094	0.009
11A-6	Table 11A-6, Line 8	2012	0.0094	0.009
11A-6	Table 11A-6, Line 8	2013	0.0095	0.010
11A-6	Table 11A-6, Line 8	2014	0.0096	0.010
11A-6	Table 11A-6, Line 12	2011	11.879	12.068
11A-6	Table 11A-6, Line 12	2012	12.736	13.107
11A-6	Table 11A-6, Line 12	2013	13.217	13.664
11A-6	Table 11A-6, Line 12	2014	13.168	13.728
11A-6	Table 11A-6, Line 13	2011	0.004	0.009
11A-6	Table 11A-6, Line 13	2012	0.004	0.009
11A-6	Table 11A-6, Line 13	2013	0.004	0.009
11A-6	Table 11A-6, Line 13	2014	0.004	0.009
11A-6	Table 11A-6, Line 14	2011	0.399	0.406
11A-6	Table 11A-6, Line 14	2012	0.416	0.428
11A-6	Table 11A-6, Line 14	2013	0.434	0.448
11A-6	Table 11A-6, Line 14	2014	0.428	0.446
11A-6	Table 11A-6, Line 17	2011	11.879	12.068
11A-6	Table 11A-6, Line 17	2012	12.736	13.107
11A-6	Table 11A-6, Line 17	2013	13.217	13.664

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-6	Table 11A-6, Line 17	2014	13.168	13.728
11A-6	Table 11A-6, Line 22	2011	5.301	5.294
11A-6	Table 11A-6, Line 22	2012	5.483	5.474
11A-6	Table 11A-6, Line 22	2013	5.788	5.785
11A-6	Table 11A-6, Line 22	2014	5.841	5.844
11A-6	Table 11A-6, Line 24	2011	0.178	0.177
11A-6	Table 11A-6, Line 24	2012	0.184	0.183
11A-7	Table 11A-7, Line 2	2011	6.9309	6.872
11A-7	Table 11A-7, Line 2	2012	7.3266	7.202
11A-7	Table 11A-7, Line 2	2013	7.7981	7.669
11A-7	Table 11A-7, Line 2	2014	7.9487	7.798
11A-7	Table 11A-7, Line 3	GA IV 2010	0.1528	0.153
11A-7	Table 11A-7, Line 3	2011	0.1046	0.100
11A-7	Table 11A-7, Line 3	2012	0.1152	0.107
11A-7	Table 11A-7, Line 3	2013	0.1271	0.118
11A-7	Table 11A-7, Line 3	2014	0.1299	0.119
11A-7	Table 11A-7, Line 4	GA IV 2010	0.3528	0.353
11A-7	Table 11A-7, Line 4	2011	0.3327	0.326
11A-7	Table 11A-7, Line 4	2012	0.3560	0.344
11A-7	Table 11A-7, Line 4	2013	0.3834	0.370
11A-7	Table 11A-7, Line 4	2014	0.3913	0.376
11A-7	Table 11A-7, Line 7	GA IV 2010	8.4044	8.404
11A-7	Table 11A-7, Line 7	2011	6.9399	6.872
11A-7	Table 11A-7, Line 7	2012	7.3266	7.202

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-7	Table 11A-7, Line 7	2013	7.7981	7.669
11A-7	Table 11A-7, Line 7	2014	7.9487	7.798
11A-7	Table 11A-7, Line 8	GA IV 2010	0.1063	0.106
11A-7	Table 11A-7, Line 8	2011	0.1046	0.100
11A-7	Table 11A-7, Line 8	2012	0.1152	0.107
11A-7	Table 11A-7, Line 8	2013	0.1271	0.118
11A-7	Table 11A-7, Line 8	2014	0.1299	0.119
11A-7	Table 11A-7, Line 9	GA IV 2010	0.3826	0.383
11A-7	Table 11A-7, Line 9	2011	0.3327	0.326
11A-7	Table 11A-7, Line 9	2012	0.3560	0.344
11A-7	Table 11A-7, Line 9	2013	0.3834	0.370
11A-7	Table 11A-7, Line 9	2014	0.3913	0.376
11A-7	Table 11A-7, Line 12	2011	7.889	7.950
11A-7	Table 11A-7, Line 12	2012	8.272	8.408
11A-7	Table 11A-7, Line 12	2013	8.669	8.828
11A-7	Table 11A-7, Line 12	2014	8.681	8.871
11A-7	Table 11A-7, Line 13	2011	0.140	0.145
11A-7	Table 11A-7, Line 13	2012	0.144	0.152
11A-7	Table 11A-7, Line 13	2013	0.149	0.158
11A-7	Table 11A-7, Line 13	2014	0.143	0.155
11A-7	Table 11A-7, Line 14	2011	0.399	0.406
11A-7	Table 11A-7, Line 14	2012	0.416	0.428
11A-7	Table 11A-7, Line 14	2013	0.434	0.448
11A-7	Table 11A-7, Line 14	2014	0.428	0.446

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-7	Table 11A-7, Line 17	2011	7.889	7.950
11A-7	Table 11A-7, Line 17	2012	8.272	8.408
11A-7	Table 11A-7, Line 17	2013	8.669	8.828
11A-7	Table 11A-7, Line 17	2014	8.681	8.871
11A-7	Table 11A-7, Line 18	2011	0.140	0.145
11A-7	Table 11A-7, Line 18	2012	0.144	0.152
11A-7	Table 11A-7, Line 18	2013	0.149	0.158
11A-7	Table 11A-7, Line 18	2014	0.143	0.155
11A-7	Table 11A-7, Line 19	2011	0.399	0.406
11A-7	Table 11A-7, Line 19	2012	0.416	0.428
11A-7	Table 11A-7, Line 19	2013	0.434	0.448
11A-7	Table 11A-7, Line 19	2014	0.428	0.446
11A-7	Table 11A-7, Line 22	2011	3.661	3.659
11A-7	Table 11A-7, Line 22	2012	3.776	3.773
11A-7	Table 11A-7, Line 22	2013	3.976	3.979
11A-7	Table 11A-7, Line 22	2014	4.037	4.039
11A-7	Table 11A-7, Line 23	2012	0.060	0.059
11A-7	Table 11A-7, Line 24	2011	0.178	0.177
11A-7	Table 11A-7, Line 24	2012	0.184	0.183
11A-8	Table 11A-8, Line 2	2011	0.333	0.326
11A-8	Table 11A-8, Line 2	2012	0.356	0.344
11A-8	Table 11A-8, Line 2	2013	0.383	0.370
11A-8	Table 11A-8, Line 2	2014	0.391	0.376
11A-8	Table 11A-8, Line 4	2011	0.333	0.326

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-8	Table 11A-8, Line 4	2012	0.356	0.344
11A-8	Table 11A-8, Line 4	2013	0.383	0.370
11A-8	Table 11A-8, Line 4	2014	0.391	0.376
11A-8	Table 11A-8, Line 6	2011	0.399	0.406
11A-8	Table 11A-8, Line 6	2012	0.416	0.428
11A-8	Table 11A-8, Line 6	2013	0.434	0.448
11A-8	Table 11A-8, Line 6	2014	0.428	0.446
11A-8	Table 11A-8, Line 8	2011	0.399	0.406
11A-8	Table 11A-8, Line 8	2012	0.416	0.428
11A-8	Table 11A-8, Line 8	2013	0.434	0.448
11A-8	Table 11A-8, Line 8	2014	0.428	0.446
11A-8	Table 11A-8, Line 10	2012	0.184	0.183
11A-9	Table 11A-9, Line 3	2011	9.899	10.057
11A-9	Table 11A-9, Line 3	2012	10.613	10.923
11A-9	Table 11A-9, Line 3	2013	11.014	11.387
11A-9	Table 11A-9, Line 3	2014	10.973	11.440
11A-9	Table 11A-9, Line 4	2012	0.007	0.008
11A-9	Table 11A-9, Line 5	2011	0.333	0.338
11A-9	Table 11A-9, Line 5	2012	0.347	0.357
11A-9	Table 11A-9, Line 5	2013	0.361	0.374
11A-9	Table 11A-9, Line 5	2014	0.357	0.372
11A-9	Table 11A-9, Line 8	2011	9.899	10.057
11A-9	Table 11A-9, Line 8	2012	10.613	10.923
11A-9	Table 11A-9, Line 8	2013	11.014	11.387

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-9	Table 11A-9, Line 8	2014	10.973	11.440
11A-9	Table 11A-9, Line 9	2012	0.007	0.008
11A-9	Table 11A-9, Line 10	2011	0.333	0.338
11A-9	Table 11A-9, Line 10	2012	0.347	0.357
11A-9	Table 11A-9, Line 10	2013	0.361	0.374
11A-9	Table 11A-9, Line 10	2014	0.357	0.372
11A-9	Table 11A-9, Line 14	2011	6.574	6.625
11A-9	Table 11A-9, Line 14	2012	6.894	7.007
11A-9	Table 11A-9, Line 14	2013	7.224	7.357
11A-9	Table 11A-9, Line 14	2014	7.234	7.392
11A-9	Table 11A-9, Line 15	2011	0.117	0.121
11A-9	Table 11A-9, Line 15	2012	0.120	0.127
11A-9	Table 11A-9, Line 15	2013	0.124	0.132
11A-9	Table 11A-9, Line 15	2014	0.119	0.129
11A-9	Table 11A-9, Line 16	2011	0.333	0.338
11A-9	Table 11A-9, Line 16	2012	0.347	0.357
11A-9	Table 11A-9, Line 16	2013	0.361	0.374
11A-9	Table 11A-9, Line 16	2014	0.357	0.372
11A-9	Table 11A-9, Line 19	2011	6.574	6.625
11A-9	Table 11A-9, Line 19	2012	6.894	7.007
11A-9	Table 11A-9, Line 19	2013	7.224	7.357
11A-9	Table 11A-9, Line 19	2014	7.234	7.392
11A-9	Table 11A-9, Line 20	2011	0.117	0.121
11A-9	Table 11A-9, Line 20	2012	0.120	0.127

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-9	Table 11A-9, Line 20	2013	0.124	0.132
11A-9	Table 11A-9, Line 20	2014	0.119	0.129
11A-9	Table 11A-9, Line 21	2011	0.333	0.338
11A-9	Table 11A-9, Line 21	2012	0.347	0.357
11A-9	Table 11A-9, Line 21	2013	0.361	0.374
11A-9	Table 11A-9, Line 21	2014	0.357	0.372
11A-9	Table 11A-9, Line 24	2011	0.399	0.406
11A-9	Table 11A-9, Line 24	2012	0.416	0.428
11A-9	Table 11A-9, Line 24	2013	0.434	0.448
11A-9	Table 11A-9, Line 24	2014	0.428	0.446
11A-9	Table 11A-9, Line 28	2011	0.399	0.406
11A-9	Table 11A-9, Line 28	2012	0.416	0.428
11A-9	Table 11A-9, Line 28	2013	0.434	0.448
11A-9	Table 11A-9, Line 28	2014	0.4283	0.446
11A-10	Table 11A-10, Line 2	2011	5.873	6.241
11A-10	Table 11A-10, Line 2	2012	5.680	6.257
11A-10	Table 11A-10, Line 2	2013	5.363	6.036
11A-10	Table 11A-10, Line 2	2014	5.056	5.885
11A-10	Table 11A-10, Line 4	2011	0.195	0.207
11A-10	Table 11A-10, Line 4	2012	0.188	0.207
11A-10	Table 11A-10, Line 4	2013	0.178	0.200
11A-10	Table 11A-10, Line 4	2014	0.168	0.195
11A-11	Table 11A-11, Line 2	2013	0.134	0.135
11A-11	Table 11A-11, Line 4	2013	0.262	0.258

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-11	Table 11A-11, Line 4	2014	0.262	0.260
11A-11	Table 11A-11, Line 6	2013	6.567	6.467
11A-11	Table 11A-11, Line 6	2014	6.573	6.518
11A-11	Table 11A-11, Line 7	2013	3.138	3.090
11A-11	Table 11A-11, Line 7	2014	3.141	3.114
11A-11	Table 11A-11, Line 8	2013	22.736	22.389
11A-11	Table 11A-11, Line 8	2014	22.758	22.566
11A-11	Table 11A-11, Line 10	2013	6.567	6.467
11A-11	Table 11A-11, Line 10	2014	6.573	6.518
11A-11	Table 11A-11, Line 11	2013	22.736	22.389
11A-11	Table 11A-11, Line 11	2014	22.758	22.566
11A-11	Table 11A-11, Line 13	2013	1.187	1.170
11A-11	Table 11A-11, Line 13	2014	1.194	1.185
11A-11	Table 11A-11, Line 14	GA IV 2010	57.00	57.000
11A-11	Table 11A-11, Line 14	2014	57.000	57.00
11A-13	Table 11A-13, Line 2	2014	0.548	0.546
11A-13	Table 11A-13, Line 3	2014	0.273	0.272
11A-13	Table 11A-13, Line 6	GA IV 2010	0.0173	0.017
11A-13	Table 11A-13, Line 7	GA IV 2010	0.0152	0.015
11A-13	Table 11A-13, Line 8	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 9	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 10	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 11	GA IV 2010	0.0325	0.033
11A-13	Table 11A-13, Line 13	GA IV 2010	0.0075	0.008

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11A-13	Table 11A-13, Line 14	GA IV 2010	0.0066	0.007
11A-13	Table 11A-13, Line 15	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 16	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 17	GA IV 2010	0.0000	0.000
11A-13	Table 11A-13, Line 18	GA IV 2010	0.0141	0.014
11A-13	Table 11A-13, Line 20	2014	0.548	0.546
11A-13	Table 11A-13, Line 21	2014	0.273	0.272

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE, A.09-09-013
ERRATA TO PREPARED TESTIMONY
DATED SEPTEMBER 18, 2009

Appendix 11B: **Traditional Backbone Rate Calculation**
Witness: **Ray Blatter**
Carl Orr

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-1	10		N/A	than
11B-2	18		11	10
11B-3	Table 11B-1, Line 1	2012	800	802
11B-3	Table 11B-1, Line 4	2012	467	468
11B-3	Table 11B-1, Line 6	2011	508	509
11B-3	Table 11B-1, Line 6	2012	531	533
11B-3	Table 11B-1, Line 6	2013	521	522
11B-3	Table 11B-1, Line 6	2014	542	543
11B-3	Table 11B-1, Line 7	2012	201	202
11B-3	Table 11B-1, Line 8	2011	2,000	2,001
11B-3	Table 11B-1, Line 8	2012	2,032	2,038
11B-3	Table 11B-1, Line 8	2013	2,030	2,031
11B-3	Table 11B-1, Line 8	2014	2,049	2,050
11B-3	Table 11B-1, Line 10	2011	30	29
11B-3	Table 11B-1, Line 10	2012	30	29
11B-3	Table 11B-1, Line 10	2013	31	30
11B-3	Table 11B-1, Line 10	2014	33	30
11B-3	Table 11B-1, Line 11	2012	111	109
11B-3	Table 11B-1, Line 11	2013	112	110
11B-3	Table 11B-1, Line 11	2014	113	111

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-3	Table 11B-1, Line 12	2012	2,143	2,148
11B-3	Table 11B-1, Line 12	2013	2,142	2,141
11B-3	Table 11B-1, Line 12	2014	2,162	2,160
11B-3	Table 11B-1, Line 15	2012	32	34
11B-3	Table 11B-1, Line 17	2011	(23)	(39)
11B-3	Table 11B-1, Line 17	2012	11	(19)
11B-3	Table 11B-1, Line 17	2013	51	17
11B-3	Table 11B-1, Line 17	2014	67	28
11B-3	Table 11B-1, Line 18	2011	(12)	(28)
11B-3	Table 11B-1, Line 18	2012	6	(23)
11B-3	Table 11B-1, Line 18	2013	44	11
11B-3	Table 11B-1, Line 18	2014	65	26
11B-3	Table 11B-1, Line 19	2011	2,105	2,089
11B-3	Table 11B-1, Line 19	2012	2,148	2,125
11B-3	Table 11B-1, Line 19	2013	2,187	2,152
11B-3	Table 11B-1, Line 19	2014	2,227	2,186
11B-3	Table 11B-1, Line 21	2011	1,024	1,015
11B-3	Table 11B-1, Line 21	2012	1,024	1,015
11B-3	Table 11B-1, Line 21	2013	1,024	1,015
11B-3	Table 11B-1, Line 21	2014	1,024	1,015
11B-3	Table 11B-1, Line 22	2011	1,042	1,033
11B-3	Table 11B-1, Line 22	2012	1,042	1,033
11B-3	Table 11B-1, Line 22	2013	1,042	1,033
11B-3	Table 11B-1, Line 22	2014	1,042	1,033

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-3	Table 11B-1, Line 23	2011	1,068	1,040
11B-3	Table 11B-1, Line 24	2011	195	193
11B-3	Table 11B-1, Line 24	2012	191	192
11B-3	Table 11B-1, Line 24	2013	187	189
11B-3	Table 11B-1, Line 24	2014	184	186
11B-3	Table 11B-1, Line 25	2011	3,329	3,282
11B-3	Table 11B-1, Line 25	2012	3,325	3,309
11B-3	Table 11B-1, Line 25	2013	3,321	3,306
11B-3	Table 11B-1, Line 25	2014	3,318	3,303
11B-3	Table 11B-1, Line 27	2011	(44)	(43)
11B-3	Table 11B-1, Line 27	2012	(44)	(43)
11B-3	Table 11B-1, Line 27	2013	(44)	(43)
11B-3	Table 11B-1, Line 27	2014	(44)	(43)
11B-3	Table 11B-1, Line 29	2011	(177)	(176)
11B-3	Table 11B-1, Line 29	2012	(171)	(170)
11B-3	Table 11B-1, Line 29	2013	(171)	(170)
11B-3	Table 11B-1, Line 29	2014	(171)	(170)
11B-3	Table 11B-1, Line 30	2011	3,152	3,106
11B-3	Table 11B-1, Line 30	2012	3,154	3,139
11B-3	Table 11B-1, Line 30	2013	3,151	3,136
11B-3	Table 11B-1, Line 30	2014	3,147	3,133
11B-3	Table 11B-1, Line 32	2011	66.78%	67.26%
11B-3	Table 11B-1, Line 32	2012	68.11%	67.69%
11B-3	Table 11B-1, Line 32	2013	69.40%	68.62%

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-3	Table 11B-1, Line 32	2014	70.76%	69.78%
11B-3	2		11	10
11B-5	Table 11B-2, Line 3	2011	$0.299	$0.305
11B-5	Table 11B-2, Line 3	2012	$0.295	$0.309
11B-5	Table 11B-2, Line 3	2013	$0.285	$0.302
11B-5	Table 11B-2, Line 3	2014	$0.275	$0.296
11B-5	Table 11B-2, Line 4	2011	30	29
11B-5	Table 11B-2, Line 4	2012	30	29
11B-5	Table 11B-2, Line 4	2013	31	30
11B-5	Table 11B-2, Line 4	2014	33	30
11B-5	Table 11B-2, Line 11	2011	2,000	2,001
11B-5	Table 11B-2, Line 11	2012	2,032	2,038
11B-5	Table 11B-2, Line 11	2013	2,030	2,031
11B-5	Table 11B-2, Line 11	2014	2,049	2,050
11B-5	Table 11B-2, Line 16	2011	82	83
11B-2	Table 11B-5, Line 16	2012	106	112
11B-2	Table 11B-5, Line 16	2013	104	105
11B-2	Table 11B-5, Line 16	2014	123	124
11B-5	Table 11B-2, Line 25	2012	162	168
11B-5	Table 11B-2, Line 25	2013	160	161
11B-5	Table 11B-2, Line 25	2014	179	180
11B-5	Table 11B-2, Line 27	2012	32	34
11B-6	Table 11B-2, Line 36	2011	411	414
11B-6	Table 11B-2, Line 36	2012	419	417
11B-6	Table 11B-2, Line 36	2013	427	422

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-6	Table 11B-2, Line 36	2014	436	430
11B-6	Table 11B-2, Line 39	2011	197	194
11B-6	Table 11B-2, Line 39	2012	188	191
11B-6	Table 11B-2, Line 39	2013	180	185
11B-6	Table 11B-2, Line 39	2014	172	178
11B-6	Table 11B-2, Line 40	2011	62.9%	58.0%
11B-6	Table 11B-2, Line 40	2012	66.5%	59.2%
11B-6	Table 11B-2, Line 40	2013	66.1%	58.1%
11B-6	Table 11B-2, Line 40	2014	68.3%	59.0%
11B-6	Table 11B-2, Line 41	2011	-37.1%	-42.0%
11B-6	Table 11B-2, Line 41	2012	-33.5%	-40.8%
11B-6	Table 11B-2, Line 41	2013	-33.9%	-41.9%
11B-6	Table 11B-2, Line 41	2014	-31.7%	-41.0%
11B-6	Table 11B-2, Line 42	2011	(73)	(81)
11B-6	Table 11B-2, Line 42	2012	(63)	(78)
11B-6	Table 11B-2, Line 42	2013	(61)	(78)
11B-6	Table 11B-2, Line 42	2014	(54)	(73)
11B-6	Table 11B-2, Line 43	2011	1,027	999
11B-6	Table 11B-2, Line 44	2011	686	672
11B-6	Table 11B-2, Line 44	2012	700	695
11B-6	Table 11B-2, Line 44	2013	713	705
11B-6	Table 11B-2, Line 44	2014	727	717
11B-6	Table 11B-2, Line 46	2011	858	834
11B-6	Table 11B-2, Line 47	2011	172	162

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-6	Table 11B-2, Line 47	2012	158	162
11B-6	Table 11B-2, Line 47	2013	145	153
11B-6	Table 11B-2, Line 47	2014	131	141
11B-6	Table 11B-2, Line 48	2011	124.5%	126.0%
11B-6	Table 11B-2, Line 48	2012	128.7%	128.4%
11B-6	Table 11B-2, Line 48	2013	136.8%	136.5%
11B-6	Table 11B-2, Line 48	2014	139.0%	138.4%
11B-6	Table 11B-2, Line 49	2011	24.5%	26.0%
11B-6	Table 11B-2, Line 49	2012	28.7%	28.4%
11B-6	Table 11B-2, Line 49	2013	36.8%	36.5%
11B-6	Table 11B-2, Line 49	2014	39.0%	38.4%
11B-6	Table 11B-2, Line 50	2012	45	46
11B-6	Table 11B-2, Line 50	2013	53	56
11B-6	Table 11B-2, Line 50	2014	51	54
11B-6	Table 11B-2, Line 51	2011	1,315	1,298
11B-6	Table 11B-2, Line 51	2012	1,321	1,304
11B-6	Table 11B-2, Line 51	2013	1,321	1,304
11B-6	Table 11B-2, Line 51	2014	1,321	1,304
11B-6	Table 11B-2, Line 52	2011	878	873
11B-6	Table 11B-2, Line 52	2012	900	883
11B-6	Table 11B-2, Line 52	2013	917	895
11B-6	Table 11B-2, Line 52	2014	935	910
11B-6	Table 11B-2, Line 53	2011	430	453
11B-6	Table 11B-2, Line 53	2012	462	466

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-6	Table 11B-2, Line 53	2013	461	460
11B-6	Table 11B-2, Line 53	2014	481	479
11B-6	Table 11B-2, Line 54	2011	(448)	(420)
11B-6	Table 11B-2, Line 54	2012	(438)	(416)
11B-6	Table 11B-2, Line 54	2013	(455)	(435)
11B-6	Table 11B-2, Line 54	2014	(454)	(431)
11B-6	Table 11B-2, Line 55	2011	98.2%	99.9%
11B-6	Table 11B-2, Line 55	2012	93.3%	96.8%
11B-6	Table 11B-2, Line 55	2013	87.2%	91.0%
11B-6	Table 11B-2, Line 55	2014	84.4%	89.1%
11B-6	Table 11B-2, Line 56	2011	-1.8%	-0.1%
11B-6	Table 11B-2, Line 56	2012	-6.7%	-3.2%
11B-6	Table 11B-2, Line 56	2013	-12.8%	-9.0%
11B-6	Table 11B-2, Line 56	2014	-15.6%	-10.9%
11B-6	Table 11B-2, Line 57	2011	8	0
11B-6	Table 11B-2, Line 57	2012	29	13
11B-6	Table 11B-2, Line 57	2013	58	39
11B-6	Table 11B-2, Line 57	2014	71	47
11B-6	Table 11B-2, Line 58	2011	(23)	(39)
11B-6	Table 11B-2, Line 58	2012	11	(19)
11B-6	Table 11B-2, Line 58	2013	51	17
11B-6	Table 11B-2, Line 58	2014	67	28
11B-6	Table 11B-2, Line 60	2011	$0.304	$0.306
11B-6	Table 11B-2, Line 60	2012	$0.316	$0.319

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-6	Table 11B-2, Line 60	2013	$0.327	$0.332
11B-6	Table 11B-2, Line 60	2014	$0.326	$0.332
11B-6	Table 11B-2, Line 61	2011	$0.191	$0.177
11B-6	Table 11B-2, Line 61	2012	$0.210	$0.189
11B-6	Table 11B-2, Line 61	2013	$0.216	$0.193
11B-6	Table 11B-2, Line 61	2014	$0.223	$0.196
11B-6	Table 11B-2, Line 62	2011	$0.299	$0.305
11B-6	Table 11B-2, Line 62	2012	$0.295	$0.309
11B-6	Table 11B-2, Line 62	2013	$0.285	$0.302
11B-6	Table 11B-2, Line 62	2014	$0.275	$0.296
11B-6	Table 11B-2, Line 63	2011	$0.378	$0.385
11B-6	Table 11B-2, Line 63	2012	$0.407	$0.410
11B-6	Table 11B-2, Line 63	2013	$0.448	$0.453
11B-6	Table 11B-2, Line 63	2014	$0.453	$0.460
11B-17	Table 11B-3, Line 2	Other Redwood (Noncore)	1,314.74	1,297.97
11B-17	Table 11B-3, Line 2	Common	1,3174.74	1,297.97
11B-17	Table 11B-3, Line 3	Line 401 (Included in Other Redwood)	888.31	880.17
11B-17	Table 11B-3, Line 5	Baja	1,027.23	999.01
11B-17	Table 11B-3, Line 5	Common	1,027.23	999.01
11B-17	Table 11B-3, Line 6	Other Redwood (Noncore)	38.94	38.65
11B-17	Table 11B-3, Line 6	Baja	38.94	38.65
11B-17	Table 11B-3, Line 6	Common	194.68	193.27

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-17	Table 11B-3, Line 7	Other Redwood (Noncore)	1,353.68	1,336.62
11B-17	Table 11B-3, Line 7	Line 401 (Included in Other Redwood)	980.15	972.00
11B-17	Table 11B-3, Line 7	Baja	1,066.16	1,037.66
11B-17	Table 11B-3, Line 7	Common	3,125.25	3,105.84
11B-17	Table 11B-4, Line 1	Redwood Core Vintage	18,335	16,270
11B-17	Table 11B-4, Line 1	Common	10,349	10,503
11B-17	Table 11B-4, Line 1	Total Backbone	28,683	26,773
11B-17	Table 11B-4, Line 2	Other Redwood (Noncore)	73,586	75,186
11B-17	Table 11B-4, Line 2	Common	22,102	22,146
11B-17	Table 11B-4, Line 2	Total Backbone	95,688	97,331
11B-17	Table 11B-4, Line 3	Line 401 (Included in Other Redwood)	63,065	66,382
11B-17	Table 11B-4, Line 4	Line 401 (Included in Other Redwood)	6,520	6,926
11B-17	Table 11B-4, Line 4	Total Backbone	6,520	6,926
11B-17	Table 11B-4, Line 5	Baja	77,486	77,727
11B-17	Table 11B-4, Line 5	Common	17,268	17,045
11B-17	Table 11B-4, Line 5	Total Backbone	94,754	94,472
11B-17	Table 11B-4, Line 6	Redwood Core Vintage	18,335	16,270
11B-17	Table 11B-4, Line 6	Other Redwood (Noncore)	75,766	77,425

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-17	Table 11B-4, Line 6	Line 401 (Included in Other Redwood)	69,585	73,308
11B-17	Table 11B-4, Line 6	Total Backbone	234,034	234,035
11B-19	Table 11B-5, Line 2	2011	5.723	5.296
11B-19	Table 11B-5, Line 2	2012	6.304	5.654
11B-19	Table 11B-5, Line 2	2013	6.484	5.770
11B-19	Table 11B-5, Line 2	2014	6.686	5.866
11B-19	Table 11B-5, Line 4	2011	0.191	0.177
11B-19	Table 11B-5, Line 4	2012	0.210	0.189
11B-19	Table 11B-5, Line 4	2013	0.216	0.193
11B-19	Table 11B-5, Line 4	2014	0.223	0.196
11B-19	Table 11B-5, Line 6	2011	9.008	9.216
11B-19	Table 11B-5, Line 6	2012	8.905	9.322
11B-19	Table 11B-5, Line 6	2013	8.598	9.111
11B-19	Table 11B-5, Line 6	2014	8.296	8.921
11B-19	Table 11B-5, Line 7	2011	0.002	0.003
11B-19	Table 11B-5, Line 7	2012	0.002	0.003
11B-19	Table 11B-5, Line 7	2013	0.002	0.003
11B-19	Table 11B-5, Line 7	2014	0.002	0.003
11B-19	Table 11B-5, Line 8	2011	0.299	0.306
11B-19	Table 11B-5, Line 8	2012	0.295	0.309
11B-19	Table 11B-5, Line 8	2013	0.285	0.302
11B-19	Table 11B-5, Line 8	2014	0.275	0.296
11B-19	Table 11B-5, Line 10	2011	11.002	00.196

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-19	Table 11B-5, Line 10	2012	11.870	11.952
11B-19	Table 11B-5, Line 10	2013	13.109	13.266
11B-19	Table 11B-5, Line 10	2014	13.281	13.471
11B-19	Table 11B-5, Line 12	2011	0.379	0.385
11B-19	Table 11B-5, Line 12	2012	0.407	0.410
11B-19	Table 11B-5, Line 12	2013	0.448	0.453
11B-19	Table 11B-5, Line 12	2014	0.453	0.460
11B-19	Table 11B-5, Line 14	2011	5.258	5.348
11B-19	Table 11B-5, Line 14	2012	5.413	5.527
11B-19	Table 11B-5, Line 14	2013	5.630	5.787
11B-19	Table 11B-5, Line 14	2014	5.618	5.805
11B-19	Table 11B-5, Line 16	2011	0.177	0.180
11B-19	Table 11B-5, Line 16	2012	0.182	0.186
11B-19	Table 11B-5, Line 16	2013	0.189	0.194
11B-19	Table 11B-5, Line 16	2014	0.189	0.195
11B-19	Table 11B-5, Footnote (b)		66.78	67.26
11B-19	Table 11B-5, Footnote (b)		68.11	67.69
11B-19	Table 11B-5, Footnote (b)		69.40	68.62
11B-19	Table 11B-5, Footnote (b)		70.76	69.78
11B-20	Table 11B-6, Line 2	2011	3.962	3.831
11B-20	Table 11B-6, Line 2	2012	4.269	4.069
11B-20	Table 11B-6, Line 2	2013	4.337	4.144
11B-20	Table 11B-6, Line 2	2014	4.422	4.202
11B-20	Table 11B-6, Line 3	2011	0.061	0.051

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-20	Table 11B-6, Line 3	2012	0.070	0.055
11B-20	Table 11B-6, Line 3	2013	0.074	0.057
11B-20	Table 11B-6, Line 3	2014	0.077	0.058
11B-20	Table 11B-6, Line 4	2011	0.191	0.177
11B-20	Table 11B-6, Line 4	2012	0.210	0.189
11B-20	Table 11B-6, Line 4	2013	0.216	0.193
11B-20	Table 11B-6, Line 4	2014	0.223	0.196
11B-20	Table 11B-6, Line 6	2011	5.567	5.644
11B-20	Table 11B-6, Line 6	2012	5.608	5.788
11B-20	Table 11B-6, Line 6	2013	5.535	5.758
11B-20	Table 11B-6, Line 6	2014	5.463	5.729
11B-20	Table 11B-6, Line 7	2011	0.116	0.120
11B-20	Table 11B-6, Line 7	2012	0.111	0.119
11B-20	Table 11B-6, Line 7	2013	0.103	0.113
11B-20	Table 11B-6, Line 7	2014	0.095	0.107
11B-20	Table 11B-6, Line 8	2011	0.299	0.305
11B-20	Table 11B-6, Line 8	2012	0.295	0.309
11B-20	Table 11B-6, Line 8	2013	0.285	0.302
11B-20	Table 11B-6, Line 8	2014	0.275	0.296
11B-20	Table 11B-6, Line 10	2011	8.252	8.399
11B-20	Table 11B-6, Line 10	2012	8.669	8.729
11B-20	Table 11B-6, Line 10	2013	9.305	9.418
11B-20	Table 11B-6, Line 10	2014	9.406	9.540
11B-20	Table 11B-6, Line 11	2011	0.107	0.109

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-20	Table 11B-6, Line 11	2012	0.122	0.123
11B-20	Table 11B-6, Line 11	2013	0.142	0.143
11B-20	Table 11B-6, Line 11	2014	0.144	0.146
11B-20	Table 11B-6, Line 12	2011	0.379	0.385
11B-20	Table 11B-6, Line 12	2012	0.407	0.410
11B-20	Table 11B-6, Line 12	2013	0.448	0.453
11B-20	Table 11B-6, Line 12	2014	0.453	0.460
11B-20	Table 11B-6, Line 14	2011	3.656	3.707
11B-20	Table 11B-6, Line 14	2012	3.752	3.810
11B-20	Table 11B-6, Line 14	2013	3.888	3.972
11B-20	Table 11B-6, Line 14	2014	3.906	4.004
11B-20	Table 11B-6, Line 15	2011	0.057	0.058
11B-20	Table 11B-6, Line 15	2012	0.059	0.60
11B-20	Table 11B-6, Line 15	2013	0.061	0.64
11B-20	Table 11B-6, Line 15	2014	0.060	0.063
11B-20	Table 11B-6, Line 16	2011	0.177	0.180
11B-20	Table 11B-6, Line 16	2012	0.182	0.186
11B-20	Table 11B-6, Line 16	2013	0.189	0.194
11B-20	Table 11B-6, Line 16	2014	0.189	0.195
11B-20	Table 11B-6, Footnote (b)		66.78	67.26
11B-20	Table 11B-6, Footnote (b)		68.11	67.69
11B-20	Table 11B-6, Footnote (b)		69.40	68.62
11B-20	Table 11B-6, Footnote (b)		70.76	69.78
11B-21	Table 11B-7, Line 2	2011	5.873	6.241

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
11B-21	Table 11B-7, Line 2	2012	5.680	6.257
11B-21	Table 11B-7, Line 2	2013	5.363	6.036
11B-21	Table 11B-7, Line 2	2014	5.056	5.885
11B-21	Table 11B-7, Line 4	2011	0.195	0.207
11B-21	Table 11B-7, Line 4	2012	0.188	0.207
11B-21	Table 11B-7, Line 4	2013	0.178	0.200
11B-21	Table 11B-7, Line 4	2014	0168	0.195

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REPLACEMENT PAGES

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changes in PG&E's cost structure. They are also necessary to reduce PG&E's exposure to certain cost recovery shortfalls. In addition, certain operational adjustments are necessary to accommodate the evolving northern California gas and electric generation markets.

2. Overview of Revenue Requirements and Rates

As summarized in Table 1-1, PG&E requests a GT&S revenue requirement of $529.1 million, effective January 1, 2011, for gas transmission and storage services. Over the period of 2011 through 2014, as indicated in Table 1-1, the average annual growth in the GT&S revenue requirement is approximately seven percent.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF REVENUE REQUIREMENTS
($ MILLIONS)

Line No.	Component	2010	2011	2012	2013	2014	CAGR
1	Backbone	241.0	234.0	247.5	~~260.1~~260.4	~~263.7~~264.6	2%
2	Local Transmission	164.0	202.8	219.5	~~235.3~~235.1	~~252.7~~251.8	11%
3	Storage	51.6	87.6	89.5	91.8	93.1	16%
4	Customer Access Charge	5.2	4.7	5.0	5.1	5.3	1%
5	Total	461.8	529.1	561.5	592.2	614.8	7%

Notes:

(1) The backbone revenue requirements include storage costs allocated to load balancing service and recovered through backbone rates.

(2) The backbone revenue requirements have not been reduced by the customer portion of the proposed net revenue sharing mechanism described in Section D.5 of this chapter.

(3) The 2010 local transmission revenue requirement excludes three "LT Adder" projects contemplated in Gas Accord IV, but not put into service.

(4) CAGR = Compound Annual Growth Rate

The 2011 through 2014 revenue requirements are driven by significant planned capital expenditures for backbone transmission, local transmission, and storage facilities, and significant increases in Operating and Maintenance (O&M) expenses, particularly integrity management expense.[2] In addition, in the Gas Accord IV settlement, PG&E agreed to an authorized 2010 revenue requirement that was well below its true cost of

[2] O&M and capital expenditures are discussed in detail in Chapters 5 and 6, respectively.

service[3] principally because it expected Market Storage revenues to exceed allocated Market Storage costs. In contrast, the revenue requirements proposed in this Application represent PG&E's full costs. PG&E is also proposing a separate mechanism to address potential revenue over-performance.

Table 1-2 summarizes PG&E's proposed 2011 through 2014 rates, which reflect the revenue requirements described above and the proposed policies set forth in this Application, also summarized in Section D of this chapter.

TABLE 1-2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF TRANSPORTATION AND STORAGE RATES
($/DTH, G-AFT @ FULL CONTRACT)

Line No.	Rate Category	2010	2011	2012	2013	2014	CAGR
1	Baja: Core	0.319	~~0.277~~0.271	~~0.297~~0.287	~~0.320~~0.308	~~0.326~~0.313	1%
2	Baja: Noncore	0.319	~~0.333~~0.338	~~0.347~~0.357	~~0.361~~0.374	~~0.357~~0.372	~~3~~4%
3	Redwood: Core	0.155	~~0.277~~0.271	~~0.297~~0.287	~~0.320~~0.308	~~0.326~~0.313	~~20~~19%
4	Redwood: Noncore	0.294	~~0.333~~0.338	~~0.347~~0.357	~~0.361~~0.374	~~0.357~~0.372	~~5~~6%
5	Silverado/Mission	0.153	0.148	0.153	0.161	0.163	~~5~~2%
6	G-XF	0.210	~~0.195~~0.207	~~0.188~~0.207	~~0.178~~0.200	~~0.168~~0.195	~~-5~~-2%
7	Local Transmission – Core ($/Dth)	0.369	0.455	0.484	0.509	~~0.548~~0.546	10%
8	Local Transmission – Noncore ($/Dth)	0.160	0.220	0.233	0.257	~~0.273~~0.272	14%
9	Core Firm Storage ($/Dth/mo)	0.109	0.127	0.131	~~0.134~~0.135	0.138	6%

Notes:

(1) The backbone rates have not been reduced by the customer portion of the proposed net revenue sharing mechanism described in Section D.5 of this chapter.

The backbone rate changes are driven by the changes in revenue requirements described above; proposed rates that fully recover backbone costs at expected throughput levels; equalization of Core Redwood-Baja rates and Noncore Redwood-Baja rates; and the fact that the Gas Accord IV Core Redwood rates were particularly depressed relative to cost of service

[3] The 2010 authorized revenue requirement was $39 million below PG&E's 2010 "Litigation" revenue requirement. See "Pacific Gas and Electric Company, 2008 Gas Transmission and Storage Rate Case, Testimony Supporting the Gas Accord IV Settlement," March 15, 2007, Table 2 ("PG&E Litigation Forecast – Revenue Requirement") and Table 4 ("Settlement Revenue Requirements").

instances, the gas is also processed for removal of natural gas liquids (e.g., light hydrocarbons), water, contaminants, or inert gases. The gas is then transported to market through an intra-provincial, inter-provincial, or interstate pipeline, or a series of such pipelines. Interstate pipelines deliver out-of-state natural gas into PG&E's gas transmission system, generally at points of interconnection along the California border. Gas produced locally in California is delivered directly into PG&E's transmission system from a gas gathering pipeline system.

Once the gas reaches PG&E's system, it typically first moves through PG&E's backbone transmission system. From there, the gas moves either off-system, to customers outside of PG&E's service territory (e.g., in southern California), or on-system, into PG&E's local transmission and distribution system, where it is delivered to end-use customers. In some instances, the gas is delivered from the backbone system to underground storage for withdrawal at a future date. Upon withdrawal from storage, the gas again moves on PG&E's ~~backbone~~ transmission system to either off-system or on-system destinations.

C. Gas Transmission Facilities

PG&E's gas system includes about 6,418 miles of transmission pipeline, 50 miles of gas gathering pipeline and more than 42,017 miles of distribution pipeline. The gas transmission facilities are broadly classified as either backbone transmission or local transmission. The two classifications are discussed below.

1. Backbone Transmission System

PG&E's backbone transmission system consists of the northern facilities (Lines 400, 401 and 2), the southern facilities (Lines 300 and 319), the Bay Area loop (Lines 107, 114, 131 and 303), and eight compressor stations that move gas through PG&E's system. Figure 2-1 shows PG&E's backbone and storage system.

Path, will be ~~2,066~~2,049 MDth/d when the replacement of two compressor units at Delevan is completed in April 2011. Table 2-1 provides a breakdown of the Redwood Path capacity, Baja Path capacity and Sacramento Municipality Utility District (SMUD) Equity interests.

TABLE 2-1
PACIFIC GAS & ELECTRIC COMPANY
PG&E PIPELINE CAPACITIES

Line No.	Pipeline/Path	Firm Receipt Point Capacity (MMcf/d)	Firm Delivery Point Capacity(a) (MDth/d)
1	Line 400	~~1,034~~1,025	~~1,042~~1,033
2	Line 401	~~1,016~~1,008	~~1,024~~1,015
3	Total Redwood Path	~~2,050~~2,033	~~2,066~~2,049
4	Line 300 (Baja Path)	1,060	1,068
5	SMUD Equity (L401)	~~43.1~~42.8	~~43.7~~43.4
6	SMUD Equity (L300)	40.7	41.0

(a) Based on a shrinkage rate of 1.20 percent for on-system and 0.9 percent for off-system and an MMcf-MDth conversion factor of 1.02. SMUD Equity's MMcf-MDth and shrinkage conversions are based on their equity contract agreement.

The northern backbone system interconnects with an interstate pipeline, TransCanada's Gas Transmission Northwest (GTN) System, near Malin, Oregon. PG&E receives Canadian natural gas and small amounts of Rocky Mountain gas from GTN,[1] and transports that gas to PG&E's load centers. With the interconnection of the Ruby Pipeline in 2011, the northern backbone system will receive larger amounts of gas supply from Rocky Mountain. In addition, the northern system also delivers gas to, and receives gas from, independent storage provider facilities. Table 2-2 provides an approximate breakdown of the storage capability of existing and proposed gas storage providers.

[1] Canadian gas enters the GTN system primarily via an interconnection with TransCanada Pipeline at Kingsgate, British Columbia on the U.S.-Canadian border. Rocky Mountain gas enters the GTN system via an interconnection with Northwest Pipeline at Stanfield, Oregon.

area to PG&E's southern backbone system.[2] PG&E then delivers the gas in turn to PG&E's load centers. PG&E's southern system can also receive gas from, or deliver gas to, Southern California Gas Company (SoCalGas) at Kern River Station. Kern River Station is connected to SoCalGas' system by Line 319, a jointly-owned PG&E-SoCalGas pipeline. PG&E and SoCalGas also have other interconnections along Line 300 that are used for mutual operational assistance, but not commercial activity.

~~The average firm delivery point capacity of the southern system, also known as the Baja Path, is 1,068 MDth/d as shown in Table 2-1.~~ The Baja Path currently has a firm capacity of 1,040 MDth/d in the non-winter months, increasing to 1,114 MDth/d in the winter.

a. Reductions in Baja Path Capacity

PG&E began to limit the sales of Baja Path firm delivery point capacity in October 2005 from 1,148 MDth/d to 1,080 MDth/d, due to changes in the off-system market and the reduction in total horsepower at the Kettleman compressor station. In October 2007, PG&E further limited the amount of Baja Path firm capacity sales to 1,040 MDth/d in the non-winter months because PG&E could not otherwise place all of the flows at Milpitas or along Line 401/Line 2 between Panoche and Creed Station. PG&E is currently limiting firm sales to 1,040 MDth/d in the non-winter months. The conditions described above have a smaller impact during the winter months. PG&E is currently limiting firm sales to 1,114 MDth/d in the winter months. The reasons for these reductions are discussed below.

(1) Lower Off-System Flows

When Line 401 went into service, many of the original Line 401 shippers delivered gas off-system to the SoCalGas system. The shippers had firm long-term contracts and utilized the contracts nearly 100 percent of the time. The minimum off-system flows into the SoCalGas system were significant, rarely dropping below

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[2] The El Paso, Transwestern, and Southern Trails pipelines connect to the San Juan Basin in northern New Mexico and the Permian Basin in west Texas. The Kern River Pipeline connects to the Rocky Mountain producing region in southern Wyoming.

(3) Placement Issues

During certain operating conditions, PG&E lacks sufficient end-use or storage injection demands along Line 300 or along Line 401/Line 2 south of Creed Station to place all of the gas that can flow on the Baja Path. Without the ability to place the gas, PG&E has to further limit the firm capacity of the Baja Path to 1,040 MDth/d in the non-winter months. During the winter months, PG&E can move 1,114 MDth/d on the Baja Path.

b. Modifications to the Baja Path Facilities

In order to address the continued reduction in the firm Baja Path capacity described above, PG&E made two changes to its facilities. First, PG&E increased the Maximum Operating Pressure (MOP) of a section of Line 300 with additional control of Pressure Limiting Station 3. The increased MOP allows for higher pressure entering the Kettleman compressor station, increasing the capacity of the Baja Path. Second, PG&E installed additional piping at the Bethany compressor station to allow the station to compress gas from south to north. Bethany was originally installed as part of the Line 401 expansion and was designed only to compress gas from north to south. By reversing the direction of compression, PG&E is able to move Baja Path supply further north, greatly reducing the placement issue during the non-winter months.

These changes allow PG&E to move ~~1,070~~1,068 MDth/d in non-winter months and 1,145 MDth/d in winter months. However, PG&E cannot offer 1,145 year round because of air emission limits at the Hinkley compressor station. PG&E has five units at the Hinkley compressor station which have an emission permit limit of 1,500 hours of operation per 12-month period. Because of this limit, PG&E is continuing to sell firm capacity up to 1,040 MDth/d in the non-winter months, and 1,114 MDth/d in the winter months.

c. Proposed Changes in the Baja Path Facilities

PG&E held an open season for Baja Path expansion capacity from May 15 to June 8, 2009. PG&E offered two proposed expansions: one included all receipt points on the Baja Path for a maximum capacity of 30 MDth/d, and a second was limited to a new receipt point at Arvin, California, interconnecting with the Kern River/Mojave pipeline, for a maximum capacity of 200 MDth/d.

PG&E received interest in the first expansion, which included all receipt points, and awarded the full 30 MDth/d for 30 months to PG&E's Electric Gas Supply. PG&E did not receive any requests for service that would require the second expansion.

PG&E plans to increase its firm Baja Path delivery capacity to ~~1,070~~1,068 MDth/d in the non-winter months and 1,145 MDth/d in the winter by retrofitting one additional compressor at the Hinkley compressor station with air emission reduction equipment.

2. Local Transmission

PG&E's local transmission system consists of non-backbone pipeline facilities with design operating pressures greater than 60 pounds per square inch gauge (psig).[3] The local transmission facilities include PG&E's non-backbone numbered transmission lines, distribution feeder mains, and PG&E's six-sevenths interest in the Standard Pacific Gas Line (Stanpac), which PG&E owns jointly with Chevron Pipe Line Company.[4] The various points of interconnection between PG&E's backbone transmission facilities and its local transmission and distribution facilities are collectively referred to as the "PG&E Citygate." The PG&E Citygate is an important trading point where many end-users in PG&E's territory buy gas from producers and marketers.

PG&E has slightly modified its Local Transmission planning standard by refining the determination of the Cold Winter Day (CWD) demand. The CWD demand was formerly calculated as 75 percent of the Abnormal Peak Day (APD) demand, which has a recurrence interval between 1-in-1 year and 1-in-4 years, depending on location. PG&E now has sufficient local weather data to determine the temperature for each planning area to support a 1-in-2 year recurrence interval for CWD. PG&E is now using area specific temperatures to determine CWD demand instead of using

[3] PG&E's gas transportation facilities with design operating pressures *less* than or equal to 60 psig are classified as distribution facilities.

[4] The Stanpac pipeline extends from the East Rio Vista Gas Field in a westerly direction to San Pablo Station in Contra Costa County.

E. Gas Transmission Service Proposals

1. Market Concentration Rules

PG&E proposes to continue the market concentration rules for backbone capacity adopted in CPUC Decision 02-08-070. However, for purposes of clarity, PG&E proposes to add language directly incorporating these rules into the G-AFT and G-NFT tariffs.

The current market concentration rules state that any market participant besides PG&E CGS cannot hold more than 30 percent of the capacity on either the Baja or Redwood Path on an annual basis after subtracting PG&E CGS capacities, wholesale customers, and SMUD's equity interest. For the Baja Path, the market concentration limit is currently 186 MDth/d. If PG&E CGS capacity is decreased by 100 MDth/d as proposed in Chapter 12, the market concentration limit would be 192 MDth/d. The market concentration limit for the Redwood Path is currently 413 MDth/d, but will increase to ~~422~~ 417 MDth/d upon replacement of the Delevan units in April 2011.

If a customer reaches the market concentration limit, PG&E is prohibited from selling the customer any additional capacity on that path. PG&E is not allowed under the rules to prohibit the customer from obtaining capacity above the limit in the secondary market. The market concentration limit applies to a market participant's holdings for the next 12 months.

PG&E reports the market concentration percentage of the top five capacity holders quarterly. PG&E also reports the market concentration percentage of the top capacity holders for the next quarter.

2. Increase the Long-Term Firm Contracting Limit on the Redwood Path

PG&E anticipates that the market may want to hold additional long-term standard firm capacity on the Redwood Path to align with corresponding commitments on the Ruby Pipeline, and for that reason is proposing to increase the maximum long-term contracting limit to 800 MDth/d. Currently, PG&E is allowed to sell up to 400 MDth/d of standard firm long-term capacity on the Redwood Path for terms up to 15 years. The Redwood Path will have a firm delivery point capacity of ~~2,066~~2,049 MDth/d. Core Procurement Groups hold 616 MDth/d and SMUD's equity interest is ~~44~~ 43 MDth/d, leaving

~~1,406~~1,390 MDth/d of capacity. Currently, PG&E has long-term firm capacity commitments of 245 MDth/d[6] and short-term firm capacity commitments of 49 MDth/d, leaving ~~1112~~1,096 MDth/d of available capacity on January 1, 2011. PG&E only has 155 MDth/d remaining of long-term firm capacity within the 400 MDth/d limit.

The construction of the Ruby pipeline to Malin will increase the competition for Redwood Path capacity. The Ruby pipeline is expected to be completed in the spring of 2011 with an initial capacity of 1,200 MDth/d. Many of the shippers on both the Ruby pipeline and the GTN pipeline have made long-term commitments for capacity and may want to extend their firm holdings to the PG&E Citygate. PG&E's proposal would allow for additional long-term capacity commitments, while still leaving ~~557~~541 MDth/d of capacity available for contracts less than five years in duration.

3. Elimination of the On/Off System Option for SFV Off-System Contracts

PG&E proposes to eliminate the On/Off System option for the SFV off-system tariff. In Application 07-12-021, PG&E requested that the Commission approve a long-term contract for PG&E's Electric Fuels Department. The proposed contract had the On/Off System option from the G-AFTOFF schedule. In Decision 08-11-032, the Commission ruled that it is inappropriate to use an off-system contract when the customer intends to deliver the gas primarily on-system:[7]

> SoCalGas/SDG&E assert that PG&E seeks to improperly use Tariff Schedule G-AFTOFF for firm on-system deliveries. We agree. G-AFTOFF is plainly intended for firm off-system deliveries. The Tariff Schedule states, in relevant part, as follows: "Applicability: This rate schedule applies to the firm transportation of natural gas on PG&E's Backbone Transmission system to the **Off-System Delivery Points**." (Emphasis added.) However, the record clearly indicates that PG&E plans to use its Redwood Path capacity primarily for on-system deliveries.[8] The proper tariff for firm on-system deliveries is G-AFT

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[6] 50 MDth/d of the 245 MDth/d long-term firm capacity is subject to CPUC approval because it has a contract out provisions tied to the completion of the Ruby Pipeline. PG&E anticipates filing for CPUC approval of the contract prior to the end of 2009. PG&E expects CPUC approval based on commission approval of a similar deal with PG&E's Electric Fuels Department (D.08-11-032).

[7] D.08-11-032, p. 37-38.

[8] 4 TR 367: 20-28.

Partnership, a private non-profit economic development corporation serving San Joaquin County, supporting the conclusion that incentives were necessary to make California a cost-competitive location for PNA and retain the PNA facility in California; and (3) a review and letter of confirmation from California Business Investment Services, the state of California's office responsible for economic development, supporting the conclusion that, but for the incentive package, including discounted gas transportation rates, PNA would likely relocate its production to a location outside California.

It has been the Commission practice to accept the judgment of California Business Investment Services in determining the need for economic development incentives, like the negotiated gas transportation contract with PNA. PG&E negotiated the structure and price of the contracts over several months. PG&E and PNA exchanged several offers involving price, term and various conditions. In the negotiations, PNA expressed a strong preference for a long-term contract that would match the duration of the investment in the new furnace. In response to the customer's need for price certainty, PG&E negotiated a set of four contracts that spread the discount over 15 years and provided predictable pricing for the term of the contracts. Two of the contracts required CPUC approval, which was obtained in Decision 09-05-026.

Additional details are provided in the direct testimony in Application 08-10-013.

b. Other Negotiated NGSA Contracts

PG&E has three other continuing negotiated NGSA contracts. The customers are located in areas where they could connect directly to the Kern River/Mojave pipeline system, bypassing PG&E.

The total volume of all four contracts is approximately 10 MDth/d. The local transmission discount adjustment for these contracts is ~~only $0.0013~~ less than $0.001 per decatherm.

D. Gas Storage Service Proposals

1. Assignments of Firm Storage Rights

PG&E proposes to continue to make assignments of firm storage rights to the Monthly Balancing service, Core Firm service and Market Storage. The current firm storage service assignments, as adopted in Decision 03-12-061, p. 103, are shown in Table 3-3.

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
ASSIGNMENT OF FIRM STORAGE RIGHTS ADOPTED IN DECISION 03-12-061

Line No.	Service	Average Injection (MDth/d)	Inventory (MMDth)	Average Withdrawal (MDth/d)
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Service	157	33.5	1,111
3	Core Firm Service Counter Cyclical	50	–	50
4	Market Storage	22	4.8	159

Table 3-4 details PG&E's proposed assignments of capacity for cost allocation. The assigned firm rights are the same for Core Firm service and Monthly Balancing service as adopted in D.03-12-061. The increase firm rights for Market Storage represent the increase in firm capacities at PG&E's existing fields excluding the Gill Ranch project.

TABLE 3-4
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED ASSIGNMENT OF FIRM STORAGE RIGHTS,
EFFECTIVE APRIL 1, 2011, FOR *COST ALLOCATION*

Line No.	Service	Average Injection (MDth/d)	Inventory (MMDth)	Average Withdrawal (MDth/d)
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Service	157	33.5	1,111
3	Core Firm Service Counter Cyclical	50	–	50
4	Market Storage	194	9.0	300
5	Market Storage Counter Cyclical	194	–	300

This assignment of firm rights is used to develop the storage units in Table 3-5 which are used to allocate costs between the three services. ~~The capacities in Table 3-4 do not include PG&E's portion of the Gill Ranch Gas Storage project.~~ In Application 08-07-033, PG&E stated that its cost for

TABLE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
GT&S OPERATING AND MAINTENANCE EXPENSE – 2008-2011
($000, NOMINAL)

Line No.	Description	2008 Actual	2009 Forecast	2010(a) Forecast	2011 Forecast
1	GT Total	99,406	106,024	106,498	137,038
2	GT Expense Program	90,250	94,779	94,779	119,757
3	Engineering and Maintenance	68,684	71,203	71,610	93,835
4	BX – Maintenance	49,323	50,257	50,664	64,170
5	DF – Mark and Locate/Stand-By	4,203	3,508	3,508	3,991
6	II – Integrity Management Program	15,158	17,438	17,438	25,674
7	Environmental	2,969	3,796	3,389	3,480
8	AK – Environmental Standing	2,556	3,301	2,894	3,003
9	AY – HCP Habitat Cult Protection	116	175	175	182
10	CR – Hazardous Waste Disposal	297	320	320	295
11	GSO Operations	10,903	11,560	11,560	13,914
12	CM – Operations	10,903	11,560	11,560	13,914
13	Wholesale Marketing	7,694	8,220	8,220	8,528
14	CX – Wholesale Marketing	7,694	8,220	8,220	8,528
15	Information Technology	3,704	5,611	4,357	8,230
16	Internal Remediation Expense	1,853	1,922	1,994	2,069
17	Electricity for Operations	1,921	2,017	3,667	5,267
18	Customer Access Charge	1,678	1,695	1,701	1,715

(a) PG&E is currently reviewing the 2010 GT&S O&M forecast. To the extent the approved forecast materially differs from that presented in this filing, PG&E will notify the California Public Utilities Commission (CPUC or Commission).

These expenses are shown in nominal year, ~~System Average Percent~~SAP dollars. When using these figures in cost of service calculations, escalation has been included using escalation rates that are appropriate for each type of expense, as discussed in the next section.

The 2011 forecast represents a 29 percent increase from 2010 costs. This is increase is due primarily to cost increases in the following areas:

- Integrity Management – a highly regulated pipeline risk management program that will have increasing costs in 2011 due to a 2012 regulatory milestone and project spend associated with meeting that milestone.
- Gas Storage Compressor Maintenance – a change from a late winter maintenance schedule to an early winter maintenance schedule for PG&E-owned storage compressors.

1. Pipeline Uprate Projects

In 2008, PG&E spent less than its historical average spend on pipeline projects to increase or maintain system capacity, also known as uprate projects. Expenditures for this type of work totaled $0.415 million in 2008, which was $1.454 million lower than the $1.868 million annual average spent on this type of work from 2003 to 2007. Pipelines uprates are typically required for one of two reasons:

- Public encroachment upon the pipeline,[1] which changes the pipeline design rating, thereby requiring PG&E to either uprate/requalify the pipeline to operate at the same pressure or take a commensurate pressure reduction.
- Customer demand driving the need for greater pipeline pressure and capacity.

Consequently, spending on uprates typically increases in times of economic growth or population growth. More information concerning alternatives when a pipeline class location event occurs can be found in Chapter 6.3.a.(1). The 2008 expenditure level was unusually low because of the economic recession that hit PG&E's service area (and the rest of the country). PG&E raised the uprate expenditure level by $1.454 million to $1.868 million for ~~2011~~2008. This adjustment amount is shown on line 1 of Table 5-2.

2. Air Quality Management District Permit Fees

PG&E pays Air Quality Management District Permitting fees that are required in various areas of the state. The permits typically run from July 1 through June 30. As a result, the Company may pay the fee either before or after January 1 of a given year. In 2008, PG&E incurred $302,300 less in Air Quality District fees than is typically incurred by the Company because the fees were paid after January 1, 2009. Therefore, the 2008 recorded expenditures were increased by $302,300 to reflect this unusual timing and the change is reflected on line 2 of Table 5-2.

[1] Public encroachment is the placement of buildings for public occupancy adjacent to the pipeline.

Table 6-1 summarizes PG&E's 2009 through 2014 GT&S capital spending plan by the MWCs used by PG&E to define the capital expenditures for GT&S projects:

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL CAPITAL EXPENDITURES (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline: MWC-26, -73, -75, -83, -84, -91, -98	~~112.3~~ 112.1	~~97.6~~ 97.4	116.1	~~128.1~~ 128.0	~~130.5~~ 130.4	~~103.9~~ 103.7	~~478.6~~ 478.2
2	Station Reliability: MWC-76, -96	98.8	~~104.4~~ 103.9	~~60.1~~ 52.3	~~49.8~~ 52.2	~~45.9~~ 47.0	58.6	~~214.2~~ 210.1
3	Environmental: MWC-12	14.4	~~24.7~~ 25.2	~~46.6~~ 54.4	~~61.3~~ 58.9	~~32.7~~ 31.4	16.2	~~156.8~~ 160.9
4	Base Other: MWC-5, -78	~~1.2~~1.1	1.6	1.1	0.9	1.0	1.0	4.0
5	Total Capital Expenditures	~~226.7~~ 226.4	~~228.3~~ 228.1	223.9	~~240.1~~ 240.0	~~209.9~~ 209.8	~~179.7~~ 179.5	~~853.6~~ 853.2

The total capital expenditures during 2011-2014 are $~~843.9~~853.2 million, or an average of $~~211.0~~213.3 million per year. The forecast is primarily based on forecasts of specific projects. From ~~2011~~ 2007 through 2014, PG&E will invest over $~~185.0~~125.0 million to install over ~~40~~35 miles of new gas transmission pipeline (24-inch ~~to 36-inch diameter~~and greater) to meet growing customer demand in the Sacramento and Fresno areas. During this same time period, PG&E will also replace compressor engines and supporting facilities at the Topock compressor station at a cost of $~~126.0~~120.4 million to meet new emissions requirements. These projects alone account for ~~37~~ 36 percent of the total capital forecast.

Reliability, safety, code compliance, new business, Work Requested by Others (WRO), and additional capacity projects make up the remaining ~~63~~ 64 percent of the forecast.

A detailed explanation of each MWC identified in the Total Capital Expenditure Forecast, and the forecast capital expenditures for that MWC, is presented in the following sections.

C. Pipeline Capital Expenditures

1. Overview (Roy A. Surges)

Table 6-2 summarizes the forecast 2009 through 2014 pipeline capital expenditures by MWC. Each MWC is discussed in detail in subsequent sections.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE CAPITAL EXPENDITURES BY MAJOR WORK CATEGORY (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline Integrity, MWC-98	~~19.6~~ 19.5	23.1	23.0	22.0	15.0	11.0	71.0
2	Pipeline Safety and Reliability, MWC-75	22.9	24.4	15.3	31.1	39.8	43.0	129.2
3	Work Requested by Others, MWC-83	6.3	8.0	8.3	8.6	~~8.9~~8.8	~~9.2~~9.1	~~35.0~~34.8
4	Gas Gathering, MWC-84	3.9	~~4.2~~4.1	2.4	2.4	2.5	2.6	9.9
5	Capacity, MWC-73	54.5	33.1	28.5	~~59.6~~ 59.5	58.9	~~34.3~~ 34.2	~~181.3~~ 181.1
6	New Business, MWC-26	3.3	~~3.4~~3.3	36.6	3.4	3.4	3.5	46.9
7	Power Plant Gas Metering, MWC-91	~~1.8~~1.7	1.4	2.0	1.0	2.0	0.3	5.3
8	Total Pipeline Capital Expenditures	~~112.3~~ 112.1	~~97.6~~ 97.4	116.1	~~128.1~~ 128.0	~~130.5~~ 130.4	~~103.9~~ 103.7	~~478.6~~478.2

2. Pipeline Integrity Management, MWC-98 (Roy A. Surges)

This category includes capital costs of upgrading pipelines to enable PG&E to inspect them with an In-Line-Inspection (ILI) tool, and mitigating damage found as a result of the inspection. PG&E operates its integrity management program in compliance with the requirements of the Department of Transportation, Code of Federal Regulations (CFR), 49 CFR, Part 192, Subpart O – Pipeline Integrity Management.

a. Code of Federal Regulations 49, Part 192, Subpart O

As directed by the 2002 Pipeline Safety Act, the Office of Pipeline Safety issued CFR 49, Subpart O – Pipeline Integrity Management. Subpart O requires all transmission pipeline operators, including Hinshaw pipeline operators such as PG&E, to implement a Pipeline Integrity Management Program to assess the integrity of all gas transmission pipelines located within a High Consequence Area (HCA). HCAs are defined as areas with 20 or more occupied dwellings, public gathering places or structures difficult to evacuate, e.g. nursing homes, hospitals, day cares, etc.[1]

Currently, 1,020 miles of PG&E's gas transmission pipeline systems are located within an HCA. This number is expected to grow as population density increases around PG&E's facilities. Subpart O requires all baseline integrity assessments to be completed by

[1] 49 CFR, Subpart O, Section 192.903.

TABLE 6-5
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE INTEGRITY, MWC-98 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline Integrity, MWC-98	~~19.6~~ 19.5	23.1	23.0	22.0	15.0	11.0	71.0

3. Pipeline Safety and Reliability, MWC-75 (Roy A. Surges)

This category includes capital costs of improving the safety and reliability of the gas transmission pipeline system. Examples of expenditures in this category include replacing high-risk, high-consequence pipeline segments and pressure regulating facilities identified by PG&E's Pipeline Risk Management Program. This MWC also includes expenditures necessary for PG&E to comply with the many subparts in 49 CFR, Part 192, which govern the construction, maintenance and operation of natural gas transmission pipelines.

The annual capital expenditures for MWC-75 range from $15.3 million in 2011 to $43.0 million in 2014. Reliability-based investment is forecast to increase as capital spending in Pipeline Integrity Management decreases. Pipeline integrity information obtained from inspection results will be included in risk assessments and be used to prioritize pipeline safety and reliability investments. Table 6-6 summarizes the capital expenditure forecast for Pipeline Safety and Reliability, MWC-75.

TABLE 6-6
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY AND RELIABILITY, MWC-75 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Safety and Reliability	~~12.4~~ 17.3	~~17.6~~ 20.0	~~11.6~~ 12.0	27.5	36.0	39.0	~~114.1~~ 114.5
2	Cathodic Protection	~~3.1~~3.2	3.1	2.0	2.2	2.3	2.4	8.9
3	Regulating Stations	~~(0.3)~~ (0.7)	~~1.0~~0.8	1.3	1.4	1.5	1.6	5.8
4	Small Pipeline Projects < $1,000,000	~~7.7~~3.1	~~2.7~~0.5	~~0.4~~–	–	–	–	~~0.4~~–
5	Total Capital Expenditures, MWC-75	22.9	24.4	15.3	31.1	39.8	43.0	129.2

crossings), magnitude of customer outages, and magnitude of gas flow lost should the pipeline segment fail.

Utilizing these characteristics, PG&E developed a risk assessment algorithm:

Risk = (Likelihood of Failure) × (Consequence of Failure)

The algorithms and associated variables used to develop the Likelihood of Failure and Consequence of Failure were derived by analyzing root cause technical data generated from pipeline failures that occurred across the nation over a 10-year period. Even though PG&E does not have a significant pipeline failure history, insights from incidents that occurred within the PG&E system were also used to establish the risk algorithms. The algorithms are reviewed annually with subject matter experts to determine if additional data or new incidents warrant a change to the algorithms.

PG&E uses these algorithms to derive risk numbers for every unique segment of gas transmission pipe. The pipeline segment risk numbers are then used to help identify, quantify, and prioritize high-risk pipeline segments. PG&E analyzes each high-risk segment and looks for engineering solutions and risk mitigation techniques to reduce pipeline risk. Pipeline risk reduction techniques include smart pigging, pipeline replacement, pipeline relocation, pipeline rehabilitation/recoating, erosion mitigation, underwater pipeline surveys, external corrosion direct assessment, internal corrosion mitigation, landowner notification, and public education programs. The RM Program ensures that PG&E is allocating capital safety and reliability dollars and resources to the highest risk pipeline segments and regulating stations within the system.

Examples of projects within this Planning Order include:

- 2011-2014 – Replace ~~7.9~~7.3 miles of Line 108 between Ripon and Stockton. This is the highest risk pipeline in the San Joaquin Valley. $~~33.6~~27.8 million.

- ~~2011~~2010-2014 – Replace ~~8~~13.9 miles of Line 107 between Livermore and Sunol. This is the highest-risk pipeline in the Bay Area. $~~35.1~~37.7 million.
- 2011-2014 – Replace 4.3 miles of Line 131 in Fremont. This is the second highest risk pipeline in the Bay Area. $~~13.4~~7.4 million.

b. Cathodic Protection Planning Order

This planning order includes the capital expenditures to comply with federal and state regulations for cathodic protection to protect buried steel gas pipelines from external corrosion. Capital projects primarily include replacement of deteriorated and failed pipeline coatings as well as corrosion prevention equipment such as anodes, rectifiers and monitoring systems.

c. Regulating Station Planning Order

This planning order contains capital projects to replace malfunctioning and obsolete equipment within existing gas regulation stations. A gas regulation station is designed to reduce and regulate high-pressure gas from either a backbone or local transmission pipeline to a lower pressure before it is delivered into a transmission line or distribution feeder main.

d. Pipeline Reliability < $1.0 Million Planning Order

This planning order is for pipeline reliability capital projects that cost less than $1.0 million each. Total expenditures for this planning order range from $~~7.7~~3.1 million in ~~2010~~2009 to zero in 2014. Projects with costs greater than or equal to $1.0 million are assigned to their own specific planning order.

4. Work Requested by Others, MWC-83 (Roy A. Surges)

This category covers plant PG&E installs, replaces, and/or relocates at the request of third parties, typically governmental agencies for public-works projects. Cities, counties, developers, Caltrans and transportation agencies such as Valley Transit Authority and Sacramento Regional Transit drive the typical WRO relocations. Capital expenditures in this category are driven entirely by existing land rights. PG&E pays zero to 100 percent of the specific project relocation costs.

PG&E's portion of the pipeline relocation costs depends on existing land rights, easements, rights of way documents and/or franchise agreements. For example, if PG&E owns the land in fee, the outside agency is responsible for paying 100 percent of the pipeline relocation costs. If PG&E's pipeline is located within a city street under a franchise agreement, PG&E typically is obligated to fund 100 percent of the cost to relocate its facilities in response to the city's request.

Table 6-7 summarizes the capital expenditure forecast for WRO, MWC-83.

TABLE 6-7
PACIFIC GAS AND ELECTRIC COMPANY
WORK REQUESTED BY OTHERS, MWC-83 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Work Requested by Others, MWC-83	6.3	8.0	8.3	8.6	~~8.9~~8.8	~~9.2~~9.1	~~35.0~~34.8

Examples of projects within this category include Caltrans highway reconstruction, installation of city sewer or storm drain lines, and new urban development. The following are examples of typical WRO projects that PG&E forecasts during this rate case period:

- 2011 – Relocate or protect in place portions of Line 114, Line 130 and Line 400 for Port of Sacramento Channel improvements. $2.6 million.
- 2011 – Relocate Line 101 for new Hillsdale Commuter Rail Station in San Mateo County. $1.4 million.
- 2012 – Relocate 1.2 miles of Line 108 for Sacramento Regional Transit Districts South Corridor light rail expansion. $2.3 million.
- 2013 – Relocate Line 118 over the San Joaquin River on State Route 99. The pipeline is currently attached to an existing bridge that is being removed and replaced. $1.0 million.

5. Gas Gathering, MWC-84 (Roy A. Surges)

This category covers capital costs associated with third party gas well connections/receipts, retirements, and divestitures of PG&E's gas gathering system.

PG&E operates about 50 miles of gas gathering pipeline and approximately 200 active California gas production receipt point meters. Other major gas gathering facilities include gas processing and dehydration stations and valve lots. Projects within this MWC include replacing and/or retiring high risk or leaking gas gathering pipelines. Anticipated projects are expected to cost less than $1.0 million each.

All new gas well production meter sets, isolation valves, service taps and extensions necessary to bring new California gas production volumes into PG&E's gas system are funded entirely by the gas producers.

Table 6-8 summarizes the capital expenditure forecast for Gas Gathering, MWC-84.

TABLE 6-8
PACIFIC GAS AND ELECTRIC COMPANY
GAS GATHERING, MWC-84 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Gas Gathering, MWC-84	3.9	~~4.2~~4.1	2.4	2.4	2.5	2.6	9.9

6. Capacity, MWC-73 (Rick C. Brown)

This category covers capital costs of installing gas transmission facilities to increase the capacity of the gas transmission system to meet customer demand. This work includes installing new gas pipelines, installing pipelines parallel to existing gas pipelines, replacing existing pipelines with a larger diameter and/or higher pressure pipeline, increasing regulating station throughput, adding new gas regulating stations, installing a main to interconnect existing gas systems, or replacing facilities to allow the system to be uprated, which increases operating pressure and capacity.

PG&E considers a variety of operational techniques and engineering design alternatives to address every system capacity constraint before recommending and implementing the preferred solution. Transmission System Planning (TSP) engineers utilize computer flow simulation models of the PG&E gas transmission network to perform system analyses and identify the most efficient capacity projects.

PG&E engineers evaluate which of the above approaches are feasible to increase system capacity and then implement the optimum alternative.

CNG and LNG peak load shaving systems are tractor-trailer-mounted tube trailers and tankers mobilized to supplement the supply of natural gas in constrained local transmission systems during Cold Winter Day and/or Abnormal Peak Day events.

Table 6-9 summarizes the capital expenditure forecast for Capacity, MWC-73.

TABLE 6-9
PACIFIC GAS AND ELECTRIC COMPANY
CAPACITY, MWC-73 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Capacity, MWC-73	54.5	33.1	28.5	~~59.6~~ 59.5	~~58.8~~ 58.9	~~34.3~~ 34.2	~~181.3~~ 181.1

During the Gas Accord IV period (2008-2010), there has been a significant increase in local transmission capacity investments. Capacity investment increases began in 2007 and were forecast to continue through 2010 and to a lesser extent into the future. The forecast local transmission capacity investment increases were driven by significant urban expansion and rapid load growth throughout the Sacramento and San Joaquin Valleys in general and in the Sacramento, Fresno, and Merced areas in particular. Capacity projects were developed to address constraints in pipelines that move gas from high pressure backbone Line 300 and Line 400/401 located on the west side of the Central Valley, to populations on the east side of the Central Valley. These major Central Valley local transmission systems—Line 138 in the Fresno area, Line 118 in the Merced and Fresno areas, and Lines 302, 172, and 108 in the Sacramento area—were mostly installed in the 1930s through the 1960s, and have met Central Valley load growth over the past 40-50 years. Up until about 2007, smaller-scale capacity projects that eliminated relatively small, localized capacity constraints were built to maintain adequate capacity. However, the ability to utilize such smaller-scale projects to solve capacity constraints was finally exhausted. Gas Demands exceeded the capacity of the major, large-diameter Central Valley

- Line 406: Scope change to 13.9 miles of 30-inch pipeline from Line 400/401 to Line 172 to meet load growth in the greater Sacramento area. Scope change is due to work performed on detailed engineering and pipeline routing. Environmental Impact Report permitting delays has resulted in a revised forecasted operational date of November 2010. Permitting delays and increased material costs have contributed to the increased project cost. $51.8 million forecast.
- Line 407 Phase 1: Scope change to 11.7 miles of 30-inch pipeline east from the east end of Line 407 Phase 2 to the Placer Vineyard development, and 2.4 miles of 10-inch pipeline from Line 407 Phase 1 south to the Sacramento Airpark on Power Line Road to meet forecasted load growth in the greater Sacramento area. Slowed load growth and delays for the development have resulted in a revised forecasted operational date of November 2012, $51.9 million forecast.
- Line 407 Phase 2: This project was not included in the last rate case, but is part of the long-term capacity strategy for serving load growth in the Sacramento area. Line 407 Phase 2 includes 14.3 miles of 30-inch pipeline from the east end of Line 406 to the west end of Line 407 Phase 1 to meet load growth in the greater Sacramento area. This project, combined with Line 406 and Line 407 Phase 1 is the final segment of a new pipeline connecting PG&E's major backbone transmission system (Line 400/401) to the greater Sacramento area. Forecast operational date is November 2013, $~~51.0~~51.1 million forecast.

Since the last rate case (Gas Accord IV), the California economy and housing market has slowed, which in turn reduced projected customer growth demands. Furthermore, pipeline engineering, project routing, permitting and material procurement put additional uncertainty in actual project construction and completion. Given the lower housing growth and pipeline project permitting delays described above, PG&E has rescheduled the installation of Line 406, Line 407 Phase 1, and Line 407 Phase 2.

7. New Business, MWC-26 (Rick C. Brown)

This category covers capital costs for gas transmission facilities extended from the existing gas transmission system to provide service to a new Noncore gas customer. The work includes procuring land rights and easements, facility design (i.e., estimating, mapping, engineering), material procurement, permitting, construction, and initial operation of the pipeline system. The majority of spending in this category is for service to natural gas-fired power plants. As discussed above in Section C.6, Capacity, MWC-73, PG&E considers a variety of engineering solutions and alternatives to meet every new business requirement before recommending and implementing the alternative with the best NPV. The same potential solutions for capacity projects are used for new business projects such as paralleling existing lines, increasing the operating pressure of pipelines, increasing regulator station capacity, etc.

Table 6-10 summarizes the capital expenditure forecast for New Business, MWC-26.

TABLE 6-10
PACIFIC GAS AND ELECTRIC COMPANY
NEW BUSINESS, MWC-26 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	New Business, MWC-26	3.3	~~3.4~~3.3	36.6	3.4	3.4	3.5	46.9

New Business capital expenditures are driven by four major factors: (1) location of the generating site in relation to PG&E's existing gas transmission and distribution system; (2) projected gas demand or load; (3) duty cycle, time of year or hours during the day that the plant will operate; and (4) existing planned investments to serve Core customer load growth. Power plants located near PG&E's backbone transmission system generally have access to an abundant supply of pipeline capacity and relatively high operating pressures. On the other hand, power plants sited near the ends of PG&E's local gas transmission systems can have detrimental effects on local system capacity and pressures. In the latter instance, major local transmission reinforcement projects may be required in order to serve these new loads. PG&E applies Gas Rules 2, 15 and 16 when determining how to serve Noncore customer loads and extension allowances.

New business projects can be difficult to forecast as they are driven by individual customers with potentially large loads as opposed to general residential load growth. The above forecast assumes an annual expenditure of about $3.5 million based on historical averages. The 2011 forecast of $36.6 million is based on known, specific new business projects. Major new business projects included in this rate case that represent the majority of 2011 spending include:

- Turlock Irrigation District (TID) Almond Power Plant in south Modesto. This project includes 12.9 miles of 24-inch to 8-inch diameter pipe to meet the customer's new business demand. To reduce the overall future costs to serve Modesto area demands, PG&E forecasts increasing the pipeline diameter for some portions of the project and connect the new line to the Modesto local transmission system thereby providing longer term capacity to Modesto at lower costs than the incremental costs of other Modesto capacity alternatives. Total project cost to serve TID Almond power plant and provide capacity to Modesto during this rate case is $~~34.0~~35.0 million. The pipeline diameter increase and the connection to the Modesto system cost about $8.0 million and are included under Capacity MWC-73. New Business, MWC-26 contains the remaining cost of the project, $~~26.0~~27.0 million. The project is forecast to be operational in 2011.

- DG Power Stockton is a new power plant located northwest of Stockton. This project requires 4.6 miles of 12-inch diameter line to serve the plant at a cost of $4.7 million and is forecast to be operational in 2011.

8. Power Plant Gas Metering, MWC-91 (Roy A. Surges)

MWC-91 captures all capital costs for the design, material procurement, and construction of gas metering and regulation facilities to serve large Noncore gas-fired power plants. Typically, these installations range in cost from $0.5 to $0.8 million given site-specific requirements and conditions.

Table 6-11 summarizes the capital expenditure forecast for Power Plant Gas Metering, MWC-91.

TABLE 6-11
PACIFIC GAS AND ELECTRIC COMPANY
POWER PLANT GAS METERING, MWC-91 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Power Plant Gas Metering, MWC-91	~~1.8~~1.7	1.4	2.0	1.0	2.0	0.3	5.3

D. Station Reliability Capital Expenditures (Roy A. Surges)

1. Overview

Table 6-12 summarizes the capital expenditure forecast for station reliability, consisting of MWC-76 and MWC-96. MWC-76, Station Reliability, includes capital costs of maintaining and/or improving the safety, reliability, and/or capacity of the gas compression stations and underground gas storage facilities. Examples of expenditures in this category are replacing equipment that has high outage frequency or excessive maintenance costs. MWC-96, Separately Funded Capital, includes capital costs related to the Gill Ranch Storage Field Project. These MWCs are divided into four Planning Orders: Line 300, Line 400/401, Gas Terminals, and Storage Facility Reliability.

TABLE 6-12
PACIFIC GAS AND ELECTRIC COMPANY
STATION RELIABILITY, MWC-76, -96 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	L-300 Station Reliability	~~11.4~~ 13.6	~~17.5~~ 13.2	~~12.0~~ 10.8	9.3	~~6.7~~7.9	9.9	37.9
2	L-400/401 Station Reliability	44.5	19.7	12.2	6.8	10.8	24.6	54.4
3	Gas Terminals	~~6.8~~2.5	~~6.7~~7.4	5.5	5.7	5.6	5.9	22.7
4	Storage Facility Reliability(a)	~~36.1~~ 38.2	~~60.5~~ 63.6	~~30.4~~ 23.8	~~28.0~~ 30.4	~~22.6~~ 22.7	18.2	~~99.2~~ 95.1
5	Total Station Reliability Capital Expenditures	98.8	~~104.4~~ 103.9	~~60.1~~ 52.3	~~49.8~~ 52.2	~~45.7~~ 47.0	58.6	~~214.2~~ 210.1

(a) MWC-96, Separately Funded Capital, is reflected in the Storage Facility Reliability Planning Order.

Forecast capital expenditures for this MWC total $~~204.5~~210.1 million for 2011-2014 and average $~~51.1~~52.5 million per year. Major investments during the 2009–2014 timeframe include: (1) Completing the Delevan K1 and K2 replacements project that were initiated in 2009; (2) annual mandated storage gas well reworks; (3) gas compressor turbine exchange projects; and (4) Whisky Slough station upgrades to well run controls and gas processing equipment. A detailed explanation of each Planning Order within the Station Reliability MWC is provided below.

2. Line 300 Station Reliability

This Planning Order funds capital investments made at compressor, metering, and regulating stations along PG&E's Line 300. It includes costs associated with maintaining and/or improving the safety and reliability of the compressor, measurement, regulating, and auxiliary equipment located at these stations. Examples of actual and anticipated projects within this Planning Order include:

- Rebuild compressor Unit K-6 at the Topock compressor station, 2009-2010, $~~2.7~~2.5 million.
- Replace the liners and rebuild the wastewater evaporation ponds at the Topock and Hinkley compressor stations, 2009-~~2011~~2013, $~~8.0~~8.2 million.
- Exchange three gas fired turbine compressor units at the Kettleman compressor station due to each unit reaching the fired hour limit for overhaul/exchange set by Solar Gas Turbines, 2010-2012, $4.5 million.
- Rebuild the Topock compressor station compressor units and power generation units, 2009-2013. This project is necessary for reliability purposes and to comply with exhaust emission requirements that are in the process of being imposed by the Mojave Desert Air Quality Management District. See Environmental Capital Request below (MWC-12) for additional project details and cost.

3. Line 400/401 Station Reliability

This Planning Order funds capital investment made within PG&E's Line 400/401 compressor stations. It includes the same kinds of costs as the Line 300 Station Reliability Planning Order. Examples of actual and anticipated projects within this Planning Order include:

- Replace compressor units K-1 and K-2 at the Delevan compressor station, 2007-2011, $~~77.4~~75.9 million. The existing units were installed in the late 1960s. They have exceeded their 30-year design life and have

Northwest Natural Gas Company.[2] In the first phase of development, PG&E will own an undivided interest in 25 percent of the project assets and GRS will own 75 percent. GRS is the project Operator through development and at least the first three years of commercial operations. Facility assets will include a 45,000-horsepower compressor station, a 28-mile, high-pressure pipeline to PG&E's Line 401, associated gas processing, metering and regulation, and up to 15 injection/withdrawal wells. The Gill Ranch Storage Field is projected to commence operations in third quarter 2010. The storage capacity will be allocated consistent with the ownership interest. PG&E's projected capital expenditure for the Phase 1 development of the Gill Ranch facility is $~~62.0~~58.4 million, spread over the period 2008-2010. Phase 1 is forecasted to be operational in mid-2010.

E. Environmental Capital Expenditures (Roy A. Surges)

Table 6-13 summarizes the Environmental capital expenditure, consisting of a single MWC (MWC-12). This MWC includes project costs to install new facilities, and replace or upgrade existing gas transmission and storage facilities, in order to comply with environmental rules and regulations.

TABLE 6-13
PACIFIC GAS AND ELECTRIC COMPANY
ENVIRONMENTAL, MWC-12 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Environmental: MWC-12	14.4	~~24.7~~ 25.2	~~46.6~~ 54.4	~~61.3~~ 58.9	~~32.7~~ 31.4	16.2	~~156.8~~ 160.9

Examples of actual and anticipated projects within this Planning Order include:

- Install selective catalytic reduction systems on three gas turbine compressor units at the Kettleman compressor station, 2008-2011, $~~17.1~~16.6 million. This project is necessary to comply with a San Joaquin Air Quality Management

[2] Gill Ranch Storage, LLC, is a wholly owned subsidiary of Northwest Natural Gas Company, DBA NW Natural. NW Natural formed Gill Ranch Storage, LLC, to develop the Gill Ranch Storage project. The new subsidiary is separate from the utility and is dedicated to serving the California market.

District (AQMD) rule regarding gas turbine exhaust emissions requirements. All three units must meet the requirements by January 1, 2012.

- Retrofit unit K-1 at the Los Medanos gas storage field, 2009-2011, $6.9 million. This project is necessary to comply with a Bay Area AQMD enacted rule requiring nitric oxide emissions reduction on stationary sources. Compliance date is January 1, 2012.
- Perform greenhouse gas (GHG) emissions reduction projects at major compressor station and storage facilities, 2011-~~2015~~2014, $10.0 million. Based upon pending implementation of GHG emissions reduction legislation and environmental stewardship, PG&E plans to reduce GHG emissions at major stations through the use of systems to recover gas in lieu of venting flare gas to atmosphere, and install equipment that minimizes fugitive GHG emissions.

1. Topock K-Units Replacement

The Topock compressor station is the first of three compressor stations located on the Line 300 gas transmission system which transports natural gas from the Arizona/California border to the San Francisco Bay Area. Topock has nine reciprocating engine driven compressor units currently in operation.

Topock was constructed in the early 1950s and the majority of the equipment at the station is over 50 years old. PG&E anticipates needing to modify or replace the nine compressor engines by 2013 to comply with more stringent exhaust emission requirements imposed by the Mojave Desert AQMD.

The Topock Rebuild Project proposes to replace or retrofit the existing nine reciprocating compressor units. The existing units are becoming less reliable and more costly to maintain. Much of the auxiliary equipment, piping and controls associated with these units have exceeded their design life and are showing signs of their age. If modification instead of replacement were chosen to comply with air emission requirements, significant capital reliability investments will have to be made to these units over the next two to five years. Accordingly, PG&E plans to replace the units. The project cost is $~~96.5~~95.4 million.

2. Topock P-Units Replacement

In addition to the gas compressor unit replacements, PG&E anticipates needing to modify or replace the four power generation engines at the Topock compressor station by 2013 to comply with exhaust emission requirements imposed by the Mojave Desert AQMD.

Like the K-Units, due to age, these P-Units are becoming less reliable and more costly to maintain. Based upon preliminary evaluation, PG&E plans to replace the units. The project cost is $25.0 million.

F. Other Capital Expenditures (Roy A. Surges)

1. Overview

The Base Other MWC is a combination of two MWCs. They have been combined into one category because their combined total is relatively small, as shown in Table 6-14. A description of each of these MWCs is provided below.

TABLE 6-14
PACIFIC GAS AND ELECTRIC COMPANY
BASE OTHER, MWC-05, -78 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Tools and Equipment, MWC-05	~~0.6~~0.5	0.3	0.3	0.3	0.3	0.3	1.2
2	Manage Buildings, MWC-78	0.6	1.3	0.8	0.6	0.7	0.7	2.8
3	Total Base Other Capital Expenditures	~~1.2~~1.1	1.6	1.1	0.9	1.0	1.0	4.0

2. Tools and Equipment, MWC-05

This MWC is used to fund the purchase of new equipment and tools for use by PG&E employees on the GT&S system.

3. Manage Buildings, MWC-78

This MWC is used to fund capital replacements and improvements to PG&E buildings and structures throughout the GT&S system. An example of such a project would be the installation of a bathroom, offices, meeting room, and storage space at a PG&E Maintenance Headquarters.

TABLE 8-1
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST

Line No.	Revenue Requirement	($000s) 2011	2012	2013	2014
1	Base Revenue Requirement	~~529,926~~ 529,928	~~561,289~~ 561,292	~~591,888~~ 591,892	~~613,895~~ 613,904
2	*Less:* Other Operating Revenues	(2,698)	(2,698)	(2,698)	(2,698)
3	*Plus:* Carrying Costs on Working Gas and Load Balancing Gas	1,852	2,866	3,042	3,583
4	Total	~~529,080~~ 529,082	~~561,457~~ 561,460	~~592,232~~ 592,236	~~614,780~~ 614,789

Note:
The calculation of Carrying Costs on Working Gas and Load Balancing Gas can be found PG&E's Chapter 11, "Cost Allocation and Rate Design," workpapers.

The 2011 base revenue requirement of $529.9 million (Line 1 of Table 8-1) is presented in Table 8-2 below, broken down by Unbundled Cost Categories (UCC).

TABLE 8-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 BASE REVENUE REQUIREMENT

Line No.	Unbundled Cost Categories	($000s)
1	GT – Gathering (501)	13,146
2	GS – Storage Services – McDonald Island (511)	65,134
3	GS – Storage Services – Los Medanos/Pleasant Creek (512)	21,454
4	GS – Storage Services – Gill Ranch (513)	11,295
5	GT – Local Transmission (520)	202,950
6	GT – Transmission: Northern Path – Line 401 (521)	~~70,277~~74,000
7	GT – Transmission: Northern Path – Line 400 (522)	~~26,779~~23,056
8	GT – Transmission: Northern Path – Line 2 (523)	4,257
9	GT – Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	11,154
10	GT – Transmission: Southern Path – Line 300 South Topock to Panoche (525)	82,263
11	GT – Transmission: Bay Area Loop (526)	16,522
12	GT – Customer Access Charge (CAC) (540)	4,697
13	Total Year 2011	~~529,926~~ 529,928

Table 8-3 shows the requested base revenue requirements, broken down by UCC, for the post-test years 2012, 2013 and 2014.

TABLE 8-3
PACIFIC GAS AND ELECTRIC COMPANY
2012-2014 BASE REVENUE REQUIREMENT

Line No.	Unbundled Cost Categories	($000s) 2012	2013	2014
1	GT – Gathering (501)	13,383	13,865	14,377
2	GS – Storage Services – McDonald Island (511)	65,973	67,750	~~68,748~~ 68,747
3	GS – Storage Services – Los Medanos/Pleasant Creek (512)	22,150	22,905	23,173
4	GS – Storage Services – Gill Ranch (513)	10,951	10,801	10,628
5	GT – Local Transmission (520)	~~219,661~~ 219,660	~~235,425~~ 235,244	~~252,844~~ 251,995
6	GT – Transmission: Northern Path – Line 401 (521)	~~68,014~~ 74,186	~~64,296~~ 71,619	~~60,685~~ 69,864
7	GT – Transmission: Northern Path – Line 400 (522)	~~31,830~~ 25,660	~~33,769~~ 26,631	~~36,125~~ 27,804
8	GT – Transmission: Northern Path – Line 2 (523)	4,749	4,614	4,589
9	GT – Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	11,166	10,859	10,559
10	GT – Transmission: Southern Path – Line 300 South Topock to Panoche (525)	91,314	103,450	106,713
11	GT – Transmission: Bay Area Loop (526)	17,142	19,026	20,141
12	GT – Customer Access Charge (CAC) (540)	4,956	5,127	5,314
13	Total	~~561,289~~ 561,292	~~591,888~~ 591,892	~~613,895~~ 613,904

B. Cost Structure

GT&S rates currently in effect are based on the all party Gas Accord IV Settlement approved in Decision 07-09-045. PG&E generally has maintained the same cost structure in this Application, with changes described below.

In PG&E's Gas Accord I, Decision 97-08-055, the Commission approved restructuring of the gas transportation and commodity sales markets in PG&E's service territory. As a result of this restructuring, customers gained the option of obtaining parts of utility services from different suppliers. This decision required PG&E to unbundle its utility services. In order to assist the Commission in determining the cost of its unbundled services, PG&E began to separate its gas Results of Operations in its various rate setting proceedings into UCCs. A UCC corresponds to a particular asset or group of assets. In Gas Accord IV, PG&E used eight UCCs for rate design purposes. In this proceeding, PG&E presents 12 UCCs in order to provide a greater level of cost granularity. However, for rate design purposes, PG&E collapses these 12 UCCs into the same eight UCCs used in Gas Accord IV, plus one new UCC for the Gill Ranch storage project.[1] Table 8-4 shows a mapping between the eight UCCs used in Gas Accord IV, and the 12 UCCs used in this proceeding.

[1] See Chapter 11, "Cost Allocation and Rate Design."

TABLE 8-5
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services- McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path -- Line 401 (521)	GT - Transmission: Northern Path -- Line 400 (522)	GT - Transmission: Northern Path -- Line 2 (523)	GT - Transmission: Southern Path -- Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path -- Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,146	65,134	21,454	11,295	202,784	69,585 73,308	~~26,779~~ 23,056	4,257	11,154	80,423	16,522	4,697	~~527,228~~ 527,230
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,146	65,134	21,454	11,295	202,950	~~70,277~~ 74,000	~~26,779~~ 23,056	4,257	11,154	82,263	16,522	4,697	~~529,926~~ 529,928
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	3,908	0	0	0	0	0	0	0	0	0	0	0	3,908
6	Storage	0	12,411	3,859	2,237	0	0	0	0	0	0	0	0	18,506
7	Transmission	0	0	0	0	42,640	4,855	6,905	415	764	24,303	5,550	0	85,432
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	313	313
9	Customer Accounts	82	147	87	0	652	20	109	0	36	383	60	1,041	2,617
10	Uncollectibles	37	181	60	31	565	196 206	~~75~~ 64	12	31	229	46	13	1,476
11	Customer Services	359	2,096	1,241	0	3,126	90	476	0	159	1,678	262	0	9,488
12	Administrative and General	2,471	4,436	2,627	88	19,816	614	3,151	140	1,077	11,627	1,883	634	48,564
13	Franchise Requirements	125	621	204	108	1,934	~~679~~ 705	~~253~~ 220	41	106	784	157	45	5,050
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Subtotal Expenses:	6,982	19,891	8,078	2,464	68,734	6,498 6,448	~~10,971~~ 10,925	608	2,173	39,004	7,959	2,047	175,355
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	415	2,713	783	348	8,456	5,324 5,318	~~802~~ 808	304	639	3,107	517	102	23,508
21	Payroll	279	529	314	12	2,226	158	342	23	67	1,277	275	86	5,589
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	State Corporation Franchise	130	1,664	464	144	3,420	2,712 2,812	~~272~~ 172	93	265	751	272	94	10,257
25	Federal Income	976	8,297	2,304	1,795	22,948	8,865 9,719	~~2,402~~ 1,548	158	1,199	5,336	1,430	251	~~55,962~~ 55,963
26	Total Taxes	1,814	13,227	3,880	2,300	37,157	~~17,062~~ 18,011	~~3,836~~ 2,888	579	2,173	10,508	2,504	536	~~95,577~~ 95,578
27	Depreciation	2,141	11,342	3,672	1,431	35,067	~~21,069~~ 21,608	~~5,507~~ 4,969	1,161	2,817	16,841	2,511	1,341	104,901
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	10,937	44,460	15,630	6,195	140,958	46,109 44,576	~~20,314~~ 18,782	2,348	7,163	66,358	12,974	3,924	~~375,833~~ 375,834
31	Net for Return	2,209	20,673	5,825	5,100	61,992	~~25,701~~ 27,891	~~6,465~~ 4,274	1,909	3,991	15,910	3,548	773	~~154,093~~ 154,094
32	Rate Base	25,128	235,190	66,263	58,021	705,252	~~292,363~~ 317,307	~~73,545~~ 48,628	21,716	45,402	180,998	40,365	8,791	~~1,753,053~~ 1,753,060
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**8.79%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

TABLE 8-6
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 RATE BASE
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	WEIGHTED AVERAGE PLANT:													
1	Plant Beginning of Year	68,287	418,384	123,937	59,136	1,355,235	~~766,923~~ 767,064	~~142,272~~ 142,132	51,934	106,235	508,725	84,157	22,319	3,707,544
2	Net Additions	884	890	1,564	10	21,134	~~0~~ 20,541	~~42,031~~ 21,496	15	118	3,863	206	1,107	~~71,823~~ 71,829
3	Total Weighted Average Plant	69,171	419,274	125,501	59,146	1,376,369	~~766,923~~ 787,604	~~184,303~~ 163,628	51,949	106,353	512,588	84,364	23,425	~~3,779,367~~ 3,779,373
	WORKING CAPITAL:													
4	Material and Supplies - Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Material and Supplies - Other	0	316	87	0	6,228	57	0	0	0	0	0	0	6,688
6	Working Cash	127	(283)	(50)	219	1,566	~~(2,149)~~ (2,134)	~~531~~ 515	105	114	1,593	21	66	1,859
7	Total Working Capital	127	33	37	219	7,794	~~(2,093)~~ (2,077)	~~531~~ 515	105	114	1,593	21	66	8,546
	ADJUSTMENTS FOR TAX REFORM ACT:													
8	Deferred Capitalized Interest	16	(145)	(41)	(0)	376	4,590	45	14	36	134	24	(1)	5,047
9	Deferred Vacation	46	301	84	0	885	22	104	35	77	346	58	32	1,990
10	Deferred CIAC Tax Effects	0	0	0	0	0	0	0	0	0	0	0	425	425
11	Total Adjustments	62	156	43	0	1,260	4,612	149	49	112	480	81	457	7,462
12	CUSTOMER ADVANCES	0	0	0	0	0	0	0	0	0	0	0	0	0
	DEFERRED TAXES													
13	Accumulated Regulatory Assets	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Accumulated Fixed Assets	6,455	31,654	8,739	1,992	132,603	~~130,248~~ 130,669	~~14,442~~ 14,022	4,937	10,671	47,668	8,188	820	398,418
15	Accumulated Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Deferred ITC	179	931	263	1	3,426	2	404	136	297	1,340	223	62	7,263
17	Deferred Tax - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Deferred Taxes	6,634	32,585	9,002	1,993	136,028	~~130,250~~ 130,670	~~14,846~~ 14,426	5,073	10,968	49,008	8,412	882	405,681
19	DEPRECIATION RESERVE	37,598	151,687	50,316	(649)	544,143	~~346,809~~ 342,161	~~96,592~~ 101,239	25,314	50,210	284,656	35,689	14,275	~~1,636,641~~ 1,636,640
20	TOTAL RATE BASE	25,128	235,190	66,263	58,021	705,252	~~292,383~~ 317,307	~~73,545~~ 48,628	21,716	45,402	180,998	40,365	8,791	~~1,753,053~~ 1,753,060

ERRATA 04/23/10

TABLE 8-7
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 INCOME TAXES AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	Revenues	13,146	65,134	21,454	11,295	202,950	70,277	74,000	~~26,779~~ 23,056	4,257	11,154	82,263	16,522	4,697	~~529,926~~ 529,928
2	O&M Expenses		6,982	19,891	8,078	2,464	68,734	~~6,445~~ 6,490	~~10,971~~ 10,925	608	2,173	39,004	7,959	2,047	175,355
3	Nuclear Decommissioning Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
4	Superfund Tax		0	0	0	0	0	0	0	0	0	0	0	0	0
5	Taxes Other Than Income		708	3,266	1,112	361	10,789	~~5,486~~ 5,479	~~1,161~~ 1,168	328	708	4,446	802	191	29,358
6	Subtotal		5,456	41,976	12,265	8,470	123,427	~~58,346~~ 62,031	~~14,647~~ 10,963	3,321	8,273	38,813	7,761	2,459	~~325,214~~ 325,215
	DEDUCTIONS FROM TAXABLE INCOME:														
7	Interest Charges		699	6,538	1,842	1,613	19,606	~~8,128~~ 8,821	~~2,045~~ 1,352	604	1,262	5,032	1,122	244	48,735
8	Fiscal/Calendar Adjustment		16	81	45	346	467	~~(53)~~ (45)	~~16~~ 8	(4)	(3)	127	4	3	1,045
9	Operating Expense Adjustments		(107)	(210)	(114)	(4)	(808)	~~(29)~~ 22	~~(41)~~ (92)	(10)	(55)	(501)	(86)	(27)	(1,993)
10	Capitalized Interest Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capitalized Inventory Adjustment		44	1	1	0	904	1	105	38	80	336	57	0	1,566
12	Vacation Accrual Reduction		(4)	(25)	(7)	(0)	(73)	(2)	(9)	(3)	(6)	(28)	(5)	(3)	(164)
13	Capitalized Other		12	22	13	0	100	0	16	1	5	59	9	3	242
14	Subtotal Deductions		660	6,408	1,780	1,956	20,196	~~8,045~~ 8,797	~~2,132~~ 1,380	625	1,284	5,024	1,102	221	49,432
	CCFT TAXES:														
15	State Operating Expense Adjustment		20	271	71	(0)	431	250	48	21	38	154	26	2	1,332
16	State Tax Depreciation - Declining Balance		0	0	0	0	0	0	0	0	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets		3,019	15,813	4,882	4,872	60,045	~~14,902~~ 16,566	~~8,828~~ 7,165	1,651	3,922	22,777	3,388	1,053	~~145,153~~ 145,154
18	State Tax Depreciation - Other		0	0	0	0	0	0	0	0	0	0	0	0	0
19	Removal Costs		119	505	99	3	3,318	~~0~~ 136	~~386~~ 250	1	10	1,924	58	64	6,485
20	Repair Allowance		0	0	0	0	0	0	0	0	0	0	0	0	0
21	Subtotal Deductions		3,817	22,997	6,832	6,831	83,989	~~23,197~~ 25,750	~~11,394~~ 8,842	2,298	5,254	29,879	4,575	1,339	~~202,401~~ 202,402
22	Taxable Income for CCFT		1,638	18,979	5,433	1,639	39,438	~~35,149~~ 36,281	~~3,253~~ 2,121	1,023	3,019	8,934	3,187	1,120	122,812
23	CCFT		145	1,678	480	145	3,486	~~3,107~~ 3,207	~~288~~ 188	90	267	790	282	99	10,857
24	State Tax Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
25	Current CCFT		145	1,678	480	145	3,486	~~3,107~~ 3,207	~~288~~ 188	90	267	790	282	99	10,857
26	Deferred Taxes - Reg Asset		0	0	0	0	0	0	0	0	0	0	0	0	0
27	Deferred Taxes - Interest		2	24	6	(0)	38	22	4	2	3	14	2	0	118
28	Deferred Taxes - Vacation		(0)	(2)	(1)	(0)	(6)	(0)	(1)	(0)	(1)	(3)	(0)	(0)	(14)
29	Deferred Taxes - Other		0	0	0	0	0	0	0	0	0	0	0	0	0
30	Deferred Taxes - Fixed Assets		(16)	(36)	(22)	(1)	(98)	(417)	(19)	1	(4)	(75)	(11)	(5)	(702)
31	Total CCFT		130	1,664	464	144	3,420	~~2,712~~ 2,812	~~272~~ 172	93	266	726	272	94	10,257

ERRATA 04/23/10

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TABLE 8-7
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 INCOME TAXES AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 201
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	FEDERAL TAXES:													
32	CCFT - Prior Year		(179)	207	115	22	3,151 4,011	4,029 ~~118~~ 135	1,124	723	1,514	25	165	11,013
33	Federal Operating Expense Adjustment	38	516	135	(0)	832	(330)	91	40	73	296	51	4	1,748
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	2,789	13,851	4,340	5,331	55,876	3,680 5,528	~~8,648~~ 6,801	1,455	3,490	21,056	3,050	1,033	~~124,598~~ 124,599
37	Federal Tax Depreciation - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Removal Costs	119	505	99	3	3,318	0 136	~~386~~ 250	1	10	1,924	58	64	6,485
39	Repair Allowance	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Preferred Dividend Credit	3	3	1	0	68	0	8	3	6	26	4	0	123
41	Subtotal Deductions	3,430	21,491	6,470	7,311	83,440	15,423 18,142	~~11,383~~ 8,665	3,248	5,586	29,840	4,290	1,487	~~193,399~~ 193,400
42	Taxable Income for FIT	2,026	20,485	5,795	1,159	39,987	42,923 43,889	~~3,263~~ 2,298	73	2,687	8,973	3,471	972	131,815
43	Federal Income Tax	709	7,170	2,028	406	13,995	15,023 15,361	~~1,142~~ 804	26	940	3,141	1,215	340	46,135
44	Deferred Taxes - Reg Asset	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0
46	Deferred Taxes - Interest	6	77	20	(0)	127	(211)	14	6	11	45	8	1	105
47	Deferred Taxes - Vacation	(1)	(8)	(2)	(0)	(23)	(1)	(3)	(1)	(2)	(9)	(2)	(1)	(52)
48	Deferred Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	263	1,058	258	1,389	8,849	(5,947) (5,430)	~~1,249~~ 733	127	249	2,160	209	(89)	9,775
50	Total Federal Income Tax	976	8,297	2,304	1,795	22,948	8,865 9,719	~~2,402~~ 1,548	158	1,199	5,336	1,430	251	~~55,962~~ 55,963
51	Effective Tax Rate: Federal	0	0	0	0	0	0	0	0	0	0	0	0	
52	Effective Tax Rate: State	0	0	0	0	0	0	0	0	0	0	0	0	

ERRATA 04/23/10

TABLE 8-8
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2012 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services- McDonald Island (511)	GS - Storage Services- Los Medanos/Pleasant Creek (512)	GS - Storage Services- Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2012
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,383	65,973	22,150	10,951	~~219,495~~ 219,494	~~67,322~~ 73,494	~~31,830~~ 25,660	4,749	11,166	89,474	17,142	4,956	~~558,591~~ 558,594
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,383	65,973	22,150	10,951	~~219,661~~ 219,660	~~68,014~~ 74,186	~~31,830~~ 25,660	4,749	11,166	91,314	17,142	4,956	~~561,289~~ 561,292
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,024	0	0	0	0	0	0	0	0	0	0	0	4,024
6	Storage	0	12,680	3,966	2,273	0	0	0	0	0	0	0	0	18,920
7	Transmission	0	0	0	0	43,708	4,965	7,073	425	783	24,912	5,693	0	87,559
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	322	322
9	Customer Accounts	85	152	90	0	676	21	113	0	38	397	62	1,075	2,708
10	Uncollectibles	37	184	62	31	612	~~189~~ 207	~~89~~ 71	13	31	254	48	14	1,563
11	Customer Services	371	2,171	1,286	0	3,234	93	493	0	164	1,735	271	0	9,818
12	Administrative and General	2,212	3,970	2,351	79	17,736	549	2,820	126	964	10,407	1,685	568	43,468
13	Franchise Requirements	128	629	211	104	2,093	~~648~~ 707	~~303~~ 245	45	106	870	163	47	5,349
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	429	769	456	15	3,437	106	547	24	187	2,017	327	110	8,424
18	Subtotal Expenses:	7,285	20,556	8,421	2,502	71,497	~~6,572~~ 6,648	~~11,437~~ 11,361	634	2,273	40,592	8,250	2,136	182,154
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	426	2,807	820	349	~~8,957~~ 8,956	~~5,324~~ 5,323	~~815~~ 817	305	636	3,672	600	108	24,818
21	Payroll	290	549	326	13	2,310	164	355	24	69	1,324	285	89	5,798
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	115	1,607	465	116	4,136	~~2,554~~ 2,829	~~602~~ 328	137	265	918	240	104	~~11,257~~ 11,258
25	Federal Income	813	7,625	2,204	1,639	26,023	~~8,563~~ 10,071	~~3,659~~ 2,152	696	1,353	6,758	1,273	318	60,922
26	Total Taxes	1,657	12,611	3,828	2,116	41,531	~~16,609~~ 18,389	~~5,448~~ 3,669	1,162	2,329	12,734	2,408	622	~~103,056~~ 103,057
27	Depreciation	2,196	11,729	3,835	1,433	37,730	~~21,069~~ 21,898	~~6,123~~ 5,294	1,162	2,823	18,314	2,664	1,378	~~110,455~~ 110,456
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,138	44,895	16,084	6,051	150,758	~~44,250~~ 46,936	~~23,008~~ 20,324	2,957	7,425	71,641	13,322	4,135	~~395,666~~ 395,667
31	Net for Return	2,246	21,078	6,066	4,900	68,903	~~23,764~~ 27,250	~~8,821~~ 5,337	1,792	3,741	19,673	3,820	821	~~165,623~~ 165,625
32	Rate Base	25,547	239,794	69,012	55,741	~~783,880~~ 783,876	~~270,350~~ 310,014	~~100,356~~ 60,712	20,385	42,559	223,811	43,454	9,338	~~1,884,226~~ 1,884,243
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

ERRATA 04/23/10

TABLE 8-9
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2013 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services- McDonald Island (511)	GS - Storage Services- Los Medanos/Pleasant Creek (512)	GS - Storage Services- Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2013
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,865	67,750	22,905	10,801	235,259 235,078	~~63,604~~ 70,927	~~33,769~~ 26,631	4,614	10,859	101,610	19,026	5,127	589,190 589,194
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,865	67,750	22,905	10,801	~~235,425~~ 235,244	~~64,296~~ 71,619	~~33,769~~ 26,631	4,614	10,859	103,450	19,026	5,127	591,888 591,892
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,145	0	0	0	0	0	0	0	0	0	0	0	4,145
6	Storage	0	12,961	4,077	2,311	0	0	0	0	0	0	0	0	19,349
7	Transmission	0	0	0	0	44,859	5,084	7,255	436	803	25,568	5,847	0	89,852
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	330	330
9	Customer Accounts	88	157	93	0	701	22 ~~179~~	117 ~~94~~	0	13	30	288	53	14 1,649
10	Uncollectibles	39	189	64	30	656	655	199	74	39	411	64	1,112	2,804
11	Customer Services	384	2,250	1,332	0	3,346	96	510	0	170	1,795	281	0	10,164
12	Administrative and General	2,298	4,124	2,442	82	18,424	571	2,929	130	1,001	10,811	1,751	590	45,154
13	Franchise Requirements	132	646	218	103	~~2,244~~ 2,242	~~613~~ 683	~~322~~ 254	44	103	986	181	49	5,641
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	522	936	555	19	4,183	130	665	30	227	2,454	397	134	10,252
18	Subtotal Expenses:	7,607	21,263	8,781	2,545	74,413 74,410	~~6,695~~ 6,785	~~11,892~~ 11,804	653	2,375	42,313	8,574	2,229	189,338
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	445	2,885	838	349	~~9,677~~ 9,657	~~5,324~~ 5,362	~~863~~ 845	312	639	3,831	635	119	25,916
21	Payroll	301	570	338	13	2,396	170	369	25	72	1,374	296	92	6,016
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	115	1,641	483	102	4,620	~~2,286~~ 2,614	~~673~~ 345	121	234	1,596	338	103	12,316
25	Federal Income	832	7,837	2,291	1,596	28,210 28,195	~~7,557~~ 9,244	~~3,859~~ 2,187	621	1,235	9,490	1,686	317	65,532 65,533
26	Total Taxes	1,706	12,957	3,965	2,061	~~45,010~~ 44,974	~~15,341~~ 17,394	~~5,780~~ 3,763	1,080	2,186	16,354	2,962	634	110,035 110,036
27	Depreciation	2,258	12,132	3,971	1,435	~~40,416~~ 40,381	~~21,069~~ 21,981	~~6,243~~ 5,367	1,175	2,831	20,207	2,963	1,413	116,113 116,114
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,571	46,351	16,717	6,041	~~159,838~~ 159,786	~~43,104~~ 46,160	~~23,915~~ 20,933	2,908	7,391	78,875	14,499	4,275	415,486 415,488
31	Net for Return	2,294	21,399	6,188	4,760	~~75,587~~ 75,477	~~21,192~~ 25,459	~~9,854~~ 5,698	1,705	3,468	24,575	4,527	852	176,402 176,404
32	Rate Base	26,096	243,451	70,399	54,157	~~859,919~~ 858,674	~~241,091~~ 289,639	~~112,102~~ 64,825	19,399	39,456	279,577	51,507	9,693	2,006,846 2,006,872
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

ERRATA 04/23/10

TABLE 8-10
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2014 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services- McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services- Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2014
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	14,377	68,748 68,747	23,173	10,628	252,678 251,829	~~59,993~~ 69,172	~~36,125~~ 27,804	4,589	10,559	104,873	20,141	5,314	611,197 611,206
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	14,377	~~68,748~~ 68,747	23,173	10,628	252,844 251,995	~~60,685~~ 69,864	~~36,125~~ 27,804	4,589	10,559	106,713	20,141	5,314	613,895 613,904
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,270	0	0	0	0	0	0	0	0	0	0	0	4,270
6	Storage	0	13,257	4,194	2,352	0	0	0	0	0	0	0	0	19,802
7	Transmission	0	0	0	0	46,000	5,201	7,434	447	824	26,218	5,999	0	92,123
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	339	339
9	Customer Accounts	91	163	96	0	726	23	121	0	40	426	67	1,149	2,903
10	Uncollectibles	40	191	65	30	704 702	~~169~~ 195	~~101~~ 77	13	29	297	56	15	1,710
11	Customer Services	397	2,331	1,380	0	3,463	99	527	0	176	1,858	290	0	10,522
12	Administrative and General	2,388	4,287	2,539	85	19,150	~~578~~ 593	~~344~~ 3,045	136	1,041	11,237	1,829	613	46,932
13	Franchise Requirements	137	655	221	101	2,402 2,410	666	265	44	101	1,017	192	51	5,856 5,851
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	522	936	555	19	4,183	130	665	30	227	2,454	397	134	10,252
18	Subtotal Expenses:	7,845	21,820	9,049	2,586	76,636 76,625	~~8,794~~ 6,907	~~12,237~~ 12,135	669	2,438	43,507	8,822	2,301	194,703
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	461	2,933	852	349	10,113 10,164	~~5,324~~ 5,394	~~870~~ 852	312	641	3,951	704	121	26,681 26,682
21	Payroll	312	591	351	14	2,486	176	382	25	75	1,426	307	96	6,241
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	126	1,647	475	87	5,438 5,409	~~2,028~~ 2,468	~~812~~ 401	119	208	1,670	354	110	13,075
25	Federal Income	884	7,884	2,262	1,542	31,479 31,629	~~6,630~~ 8,764	~~4,391~~ 2,408	619	1,143	9,634	1,778	348	68,744 68,745
26	Total Taxes	1,795	13,079	3,954	1,992	~~49,823~~ 49,593	~~14,163~~ 16,807	~~6,472~~ 4,061	1,077	2,072	16,743	3,153	679	115,002 115,004
27	Depreciation	2,339	12,438	4,048	1,436	~~43,324~~ 43,178	~~21,069~~ 22,149	~~6,392~~ 5,460	1,198	2,842	20,871	3,182	1,449	120,587 120,588
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,979	47,338	17,051	6,014	~~169,763~~ 169,398	~~42,025~~ 45,862	~~25,102~~ 21,655	2,943	7,352	81,120	15,157	4,428	430,291 430,295
31	Net for Return	2,398	21,410	6,122	4,614	~~83,061~~ 82,599	~~18,660~~ 24,002	~~11,023~~ 6,148	1,646	3,206	25,593	4,984	886	183,604 183,609
32	Rate Base	27,286	243,571 243,570	69,648	52,489	944,949 939,692	~~212,286~~ 273,059	~~125,407~~ 69,944	18,726	36,479 36,478	~~291,164~~ 291,163	56,705	10,074	2,088,784 2,088,836
	RATE OF RETURN:													
33	On Rate Base	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%
34	On Equity	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%	11.35%

ERRATA 04/23/10

TABLE 10-1
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST COMPARISON
(MDTH/DAY)

Line No.		2008	2011	2012	2013	2014
1	Core					
2	Residential	548	554	~~555~~557	556	552
3	Commercial	234	233	~~238~~239	243	243
4	Small Commercial	213	212	~~217~~218	221	221
5	Large Commercial	20	21	21	22	22
6	Interdepartmental	0	0	0	0	0
7	Core Natural Gas Vehicles	5	6	6	6	6
8	Total Core	787	793	~~800~~ 802	805	802
9	Noncore					
10	Industrial	484	464	465	468	469
11	Industrial Distribution	69	69	69	71	72
12	IndustrialTransmission	415	395	396	397	396
13	Noncore Natural Gas Vehicles	1	1	1	2	2
14	Cogeneration	200	201	201	201	201
15	Power Plants and Miscellaneous Electric Generation	598	~~508~~509	532	522	543
16	Total Noncore	1,283	~~1,174~~ 1,175	1,199	1,192	1,214
17	Wholesale	10	10	10	10	10
18	Total Volumes	2,080	~~1,977~~ 1,978	~~2,009~~ 2,011	2,007	2,026

B. Core and Noncore Gas Demand Forecast (Other Than Electric Generation) (Kate M. Tiedeman)

1. Forecasting Methodology

PG&E forecasts gas demand by various means. Some categories of gas demand are forecasted using econometric models, which rely on statistical analysis of historical data to derive relationships between economic and demographic data and gas demand. Other categories of gas demand are forecasted using external forecasts, which rely on information from customers, account service representatives and other sources.

Econometric models are used to develop demand forecasts for residential, small commercial, large commercial and Noncore industrial customer classes. The relationships between gas demand and factors such as economic and demographic activity, prices, weather, and seasonal-use patterns are developed based on historical data. The final specification of a

Application 08-07-031 are 2,500 thousand decatherms (MDth), 2,000 MDth, 3,200 MDth and 3,100 MDth for years 2011, 2012, 2013 and 2014, respectively. PG&E has built these reductions into the forecast used in developing PG&E gas demand for this GT&S rate case period.

3. Core Demand Forecast

Core demand is projected to average approximately 800 MDth/d during 2011-2014. The Core forecast demands are shown in Table 10-1. A discussion of the major customer groups composing the Core class follows.

a. Residential Demand

For the GT&S rate case period 2011-2014, PG&E projects residential usage to average approximately ~~554~~ 555 MDth/d. This is about ~~0.8~~1.2 percent ~~below~~ above the recorded 2008 amount. Month-to-month, residential gas demand is primarily driven by temperature, with smaller economic and price effects. It is the longer-term impacts of EE programs and building standards that have driven residential usage lower both on a per household basis and total basis.

b. Commercial Demand

The projected annual average usage for commercial gas demand[2] during the GT&S rate case period is approximately 239 MDth/d, ~~2.0~~2.1 percent above the 2008 level.

4. Noncore Demand Forecast

Proposed Noncore non-EG demand is projected to be about 468 MDth/d during the GT&S rate case period. The forecast of Noncore demand is shown in Table 10-1. A discussion of the major non-EG customer classes composing Noncore follows.

a. Industrial Distribution Demand

The projected demand for the industrial distribution[3] class of customers averages ~~just under~~ about 70 MDth/d over the 2011-2014

[2] To qualify for this rate schedule, a core customer's average monthly gas use must not have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

GT&S rate case period. This is ~~1.9~~about 2.0 percent higher than the recorded 2008 amount of 69 MDth/d.

b. Industrial Transmission Demand

The projected demand for the industrial transmission customer class[4] is 393 MDth/d for the 2011-2014 GT&S rate case period, about ~~5.0~~4.5 percent below 2008 recorded.

c. Industrial Backbone Demand

There are currently three Noncore industrial customers that receive backbone level service. Their combined average usage for the 2011-2014 period is projected at 3.2 MDth/d, about ~~2.2~~3.0 percent below the recorded 2008 amount of 3.3 MDth/d. Backbone-level end use service began in 2005.

5. Wholesale Demand Forecast

PG&E currently serves six wholesale customers: the city of Palo Alto, the city of Coalinga, West Coast Gas (Castle and Mather Field locations), Island Energy, and Alpine Natural Gas. The first two customers account for over 90 percent of total wholesale demand, and the first customer accounts for over 85 percent of total wholesale demand. The forecasts for these customers' loads are based on customer-specific information collected from the customers.

The proposed annual average gas demand for these six customers is projected to be 10 MDth/d for the GT&S rate case period—~~about 1.4 percent above~~virtually constant compared to the 2008 recorded amount.

6. Summary of On-System Cold Year Demand Forecast

Table 10-2 shows the total on-system demand forecast for cold temperature conditions. This forecast is developed for a 1-in-35 cold year

[3] To qualify for the industrial distribution rate schedule, a customer's average monthly gas use must have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

[4] To qualify for the industrial transmission rate schedule, a customer must be of noncore status, which means that it must have maintained an average monthly usage in excess of 20,800 therms during the previous year, excluding those months in which usage was 200 therms or less. To the extent that its average monthly usage exceeds 250,000 therms, it is connected to facilities that are on transmission pressure (greater than 60 psi).

scenario. The cold year peak month (January) demands are used to allocate local transmission costs between Core and Noncore customer classes.

TABLE 10-2
PACIFIC GAS AND ELECTRIC COMPANY
COLD YEAR GAS DEMAND FORECAST
(MDTH/DAY)

Line No.		2008	2011	2012	2013	2014
1	Core					
2	Residential	548	615	~~617~~619	620	620
3	Commercial	234	250	256	261	262
4	Small Commercial	213	228	~~233~~234	238	239
5	Large Commercial	20	22	22	23	23
6	Interdepartmental	0	0	0	0	0
7	Core Natural Gas Vehicles	5	6	6	6	6
8	Total Core	787	871	~~879~~881	887	888
9	Noncore					
10	Industrial	484	466	469	472	471
11	Industrial Distribution	69	72	73	75	75
12	Industrial Transmission	415	395	396	397	396
13	Noncore Natural Gas Vehicles	1	1	1	2	2
14	Cogeneration	200	201	201	201	201
15	Power Plants and Miscellaneous Electric Generation	598	~~514~~515	538	~~528~~529	551
16	Total Noncore	1,283	1,183	1,209	~~1202~~ 1,204	1,225
17	Wholesale	10	13	11	11	11
18	Total Volumes	2,080	~~2066~~ 2,067	~~2098~~ 2,101	~~2099~~ 2,102	2,124

C. Electric Generation Gas Demand Forecast (Eric Hsu)

This section presents forecasts of natural gas deliveries by PG&E to electric generators. For forecasting, PG&E divides electric generators into three groups, defined as follows:

- Cogeneration. This group consists of gas-fired cogenerators whose output is generally not sensitive to prices in the electricity and gas markets because they generate electricity along with some other energy product, usually steam. Many of these plants have Qualifying Facility contracts that require PG&E to purchase their power but do not allow PG&E to dispatch them. This group includes all but ~~one~~ three of the 235 cogenerators that have had gas delivered by PG&E since the beginning of 2008.

- Power plants. This group consists of gas-fired electric generators whose output varies in response to prices in the wholesale electricity and gas markets. The power plant group includes combined cycle power plants, gas turbine (GT or "peaker") plants, and old steam-boiler plants. The power plant group also includes the cogeneration ~~plant~~plants that ~~was~~were not included in the cogeneration group (defined above) because ~~its contract with PG&E allows PG&E to dispatch it~~some or all of their generation is dispatchable. Finally, the power plant group includes gas deliveries to the Sacramento Municipal Utility District (SMUD) power plants in excess of SMUD's 88 MDth/d equity share of pipeline capacity (including both firm and as-available). Gas deliveries to SMUD in excess of its equity share are subject to PG&E rates and are therefore included in PG&E's forecasts for rate-setting purposes.
- Miscellaneous. This group consists of the remaining 17 electric generators that are neither in the cogeneration nor power plants groups (defined above). Each of these generators consumes 2.5 MDth/d or less. Of the 17 generators in this group, 13 use solar energy or biomass as their primary fuel but use gas as a secondary fuel.

1. Forecast of Cogeneration and Miscellaneous Electric Generation Gas Demand

PG&E's forecasts of cogeneration and miscellaneous electric generation gas demand are 201 and 8 MDth/d, respectively, based on the most recent 12 months of actual deliveries (June 2008 through May 2009). This approach was used in previous GT&S rate cases and BCAPs. The cogeneration forecast is marginally more than the calendar 2008 demand of 200 MDth/d. The miscellaneous electric generation forecast is slightly more than the calendar 2008 demand of 6 MDth/day.

The 20 largest accounts consume over 83 percent of the total; most of the remaining accounts consume less than 0.1 MDth/d. PG&E's database of large electrical and gas interconnection projects currently includes no cogeneration or combined heat-and-power projects under development that would take PG&E gas service. New and proposed plants are brought to PG&E's attention for provision of gas service; in contrast, no advance notice is needed for shutdowns. To the best of PG&E's knowledge, none of

PG&E's large cogeneration customers plans to expand or shut down during the rate-case period.

Smaller cogeneration and miscellaneous generators have been starting and ending their gas service at about the same rate. Between June 2006 and May 2009, PG&E has begun serving 16 new cogeneration and miscellaneous generators that collectively use about 0.6 MDth/d, while service ended to four facilities that collectively used about 2.1 MDth/d.

In view of recent history, PG&E believes the most reasonable forecasts of cogeneration and miscellaneous electric generation gas demands for the rate case period are the most recent 12 months of actual gas demands. If higher forecasts are adopted, the forecast of gas demand for power plants should be reduced. Higher gas demand by cogeneration and miscellaneous generators implies greater output of electricity, which would reduce the demand for electricity from power plants.

2. Forecast of Power Plant Gas Demand

PG&E's forecast of gas deliveries to power plants is ~~500~~501 MDth/d in 2011, 524 MDth/d in 2012, 514 MDth/d in 2013, and 535 MDth/d in 2014. These amounts have been reduced by PG&E's forecast of gas delivered to power plants by other pipelines. The numbers in Table 10-1 include the forecast of miscellaneous electric generation gas demand of 8 MDth/d described in the previous section.

Power plants connected to the PG&E gas system operate within a wholesale electricity market that spans the western United States (U.S.) and parts of Canada and Mexico. A substantial portion of electric generating capacity in this market is conventional (not pumped storage) hydroelectric. Gas-fired power plants make up most of the hydroelectric generation lost in dry years and generate less in wet years. Actual gas demand by power plants connected to the PG&E gas system was 598 MDth/d in 2008, a very dry year in northern California.

a. Modeling Methodology

PG&E's power plant gas demand forecast is based on results from the MarketBuilder program. (MarketBuilder is a registered trademark of MarketPoint Inc. of Los Altos, CA.) MarketBuilder is an economic-equilibrium program that has been applied to various markets

3. Summary of Proposed 2011 Rates

PG&E's proposed 2011 end-use rates are summarized in Table 11-1 and presented in detail in Appendix 11A following this chapter (2011-2014).

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
CLASS AVERAGE GAS ACCORD IV (GA IV) AND
PROPOSED 2011 RATES
ILLUSTRATIVE CLASS AVERAGE RATES
($/DTH)

Line No.	Customer Class	2010 Rates	Proposed 2011 Rates	$ Change(e)	% Change
1	Bundled-Retail Core(a)				
2	Residential	$13.854	$~~14.052~~ 14.044	$~~0.198~~0.190	1.4%
3	Small Commercial	$11.925	$~~12.117~~ 12.109	$~~0.192~~0.185	~~1.6~~1.5%
4	Large Commercial	$9.747	$~~9.917~~ 9.910	$~~0.169~~0.163	1.7%
5	Uncompressed Core Natural Gas Vehicle (NGV)	$8.757	$~~8.919~~ 8.913	$~~0.162~~0.156	~~1.9~~1.8%
6	Compressed Core NGV	$17.864	$~~17.949~~ 17.943	$~~0.084~~0.079	~~0.5~~0.4%
7	Transport Only-Retail Core(b)				
8	Residential	$5.494	$5.580	$0.086	1.6%
9	Small Commercial	$3.672	$3.758	$0.086	~~2.4~~2.3%
10	Large Commercial	$1.846	$1.932	$0.086	4.7%
11	Uncompressed Core NGV	$0.962	$1.048	$0.086	8.9%
12	Compressed Core NGV	$10.070	$10.156	$0.086	0.9%
13	Transport Only-Noncore(c)				
14	Industrial – Distribution	$1.505	$~~1.589~~ 1.559	$0.054	3.6%
15	Industrial – Transmission	$0.581	$0.637	$0.056	9.7%
16	Industrial – Backbone	$0.371	$0.364	($0.007)	(1.9%)
17	Uncompressed Noncore NGV – Distribution	$1.387	$1.447	$0.060	4.4%
18	Uncompressed Noncore NGV – Transmission	$0.512	$0.573	$0.060	11.8%
19	Electric Generation – Distribution/Transmission	$0.203	$0.266	$0.063	~~31.1~~31.0%
20	Electric Generation – Backbone	$0.043	$0.036	($0.007)	~~(15.6%)~~ (15.5%)
21	Transport Only-Wholesale Core(d)				
22	Alpine Natural Gas	$0.254	$0.280	$0.026	10.2%
23	Coalinga	$0.246	$0.288	$0.042	17.1%
24	Island Energy	$0.452	$0.406	($0.046)	(10.2%)
25	Palo Alto	$0.179	$0.239	$0.060	33.4%
26	West Coast Gas – Castle	$0.847	$0.744	($0.104)	(12.2%)
27	West Coast Gas – Mather Distribution	$0.784	$0.835	$0.052	6.6%
28	West Coast Gas – Mather Transmission	$0.255	$0.307	$0.052	20.3%

(a) Bundled retail Core rates include proposed backbone transmission, local transmission and storage rate changes.
(b) Transport only retail Core rates include proposed local transmission rate changes.
(c) Transport only Noncore rates include proposed customer access charge and local transmission rate changes.
(d) Transport only wholesale Core rates include proposed customer access charge and local transmission rate changes.
(e) Dollar differences are due to rounding.

backbone transmission service. Core backbone transmission capacity costs receive balancing account treatment.

3. Proposals

a. Preliminary Cost Allocation

PG&E proposes to allocate the backbone transmission revenue requirement, with the exception of revenues associated with G-XF contracts, based on customer demands on the Redwood/Baja paths and the Silverado path. The G-XF revenue requirement will continue to be determined based on G-XF customers' firm contract quantities.

The cost allocation process excludes the costs, capacities, and demands associated with the Sacramento Municipal Utility District's (SMUD) equity interest in Lines 300 and 401. SMUD owns approximately 41.0 thousand decatherms per day (MDth/d) of Line 300 capacity and ~~43.7~~43.4 MDth/d of Line 401 capacity.

Table 11-3 summarizes the customer demands and backbone capacities used to allocate costs to each path based on the forecast customer demands and Silverado path flows presented in Chapter 10. "Throughput Forecast" and the Line 401 capacity described in Chapter 2, "PG&E's Gas Transmission Facilities and Services."

TABLE 11-3
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED 2011 – 2014 BACKBONE COST ALLOCATORS
(MDTH/D)

Line No.	Rate Path	Lines 400/2, Lines 401(non G-XF), and Line 300/319 Cost Allocators	Common Cost Allocators	Line 401 Cost Allocators(a)
1	Redwood/Baja	1,892	1,892	
2	Silverado	52(b)	130	
3	Line 401 G-XF			92
4	Line 401 Non-G-XF			~~888~~880
5	Total	1,944	2,022	~~980~~972

(a) Used only to allocate Line 401 costs to G-XF contracts.

(b) The Silverado path receives a partial (40%) allocation of costs on Lines 400/2, 401, and 300/319. Therefore, the cost allocator is 40% of Silverado path flows.

Table 11-4 summarizes the costs initially allocated to each backbone transmission path based on the firm contract usage amounts shown in Table 11-3, above.

TABLE 11-4
PACIFIC GAS AND ELECTRIC COMPANY
INITIAL 2011 COST ALOCATION TO BACKBONE PATHS
($000)

Line No.	Rate Path	Line 400/2, Line 401(non G-XF), and Line 300/319	Common	G-XF	Total
1	Redwood/Baja	$~~169,855~~ 169,461	$~~49,584~~ 49,585		$~~219,439~~ 219,046
2	Line 401 G-XF			$~~6,520~~6,926	~~6,520~~6,926
3	Silverado/Mission	~~4,669~~4,657	3,407		~~8,076~~8,064
4	Total	$~~174,524~~174,118	$52,991	$~~6,520~~6,926	$~~234,035~~ 234,036

b. Final Cost Allocation and Rate Design

PG&E proposes to equalize Core Redwood/Baja rates and to equalize Noncore Redwood/Baja rates. The rationale for this change is described in Chapter 1, "Introduction and Policy." PG&E does not propose to equalize Core and Noncore rates or to eliminate the benefit of the Core's current vintage Line 400 Redwood rate. In addition, as explained in Chapter 2, backbone shippers will still hold capacity rights at specific receipt points on either the Redwood path or the Baja path.

PG&E will continue to set a single Silverado rate applicable to all Core and Noncore shippers. And, as noted above, PG&E is not proposing any changes to the Schedule G-XF rate.

As described in Chapter 1, PG&E also proposes to utilize a demand-based rate design. The steps in the proposed backbone cost allocation and rate design are as follows:

- **Step 1:** Calculate preliminary fully equalized Core/Noncore Redwood/Baja SFV and MFV rates for annual firm service (Schedule G-AFT). The cost allocation and rate calculations are based on the combined revenue requirements and forecast demands for the Redwood and Baja paths. Silverado costs and forecast demands are excluded from this calculation. Schedule G-XF costs and demands are also excluded.

- **Step 2:** In order to preserve the benefit of the Core's current vintage Line 400 Redwood rate, the preliminary Core Redwood/Baja rate derived in Step 1 is adjusted downward by the difference between what Core customers would pay for Redwood capacity under fully equalized Redwood rates and what they would pay under vintage Line 400 rates. The preliminary Noncore Redwood/Baja rate is then adjusted upward to make up for the reduction in Core revenues. As a result of this step, the cost allocation shown in Table 11-4 is modified as shown in Table 11-5.

TABLE 11-5
PACIFIC GAS AND ELECTRIC COMPANY
FINAL 2011 COST ALLOCATION TO BACKBONE PATHS
($000)

Line No.	Rate Path	Total
1	Core Redwood/Baja	$~~105,430~~ 103,267
2	Noncore Redwood/Baja	~~114,009~~ 115,778
3	Line 401 G-XF	~~6,520~~6,926
4	Silverado/Mission	~~8,076~~8,064
5	Total	$234,035

- **Step 3:** The cost allocations shown in Table 11-5 form the basis for Schedule G-AFT backbone rates. However, PG&E charges a 20 percent premium as-available service (Schedule G-AA), seasonal firm service (Schedule G-SFT), and certain negotiated firm services (Schedule G-NFT). Consequently, the Schedule G-AFT backbone rates derived from the cost allocation shown on Table 11-5 must be adjusted downward to offset this 20 percent premium. This adjustment is accomplished through an upward adjustment to throughput which, in effect, corrects the throughput for premium rate services to full (rather than premium) rate-equivalent throughput.

- **Step 4:** An upward adjustment is also made to backbone throughput to account for reservation charges paid for unused (or partially unused) firm contracts. Such reservation charges produce revenues unconnected to any throughput, and thus cause an over-collection of backbone costs, absent this correction.

- **Step 5:** Finally, a downward adjustment is made to backbone throughput to reflect the rate discount for Pilkington North America described in Chapter 2.

The steps used to develop PG&E's proposed demand-based MFV 2011-2014 rates are shown in detail in PG&E's workpapers on pages WP 11-1 through WP 11-28. Workpapers showing the development of demand-based SFV 2011-2014 rates are found on pages WP 11-29 through WP 11-56.

c. Resulting Backbone Rates

PG&E's proposed G-AFT and G-XF backbone transmission rates are summarized in Table 11-6. A detailed summary of rates for all of PG&E's backbone transmission services is presented in Appendix 11A, Tables 11A-4 through 11A-10.

TABLE 11-6
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 PROPOSED G-AFT AND G-XF BACKBONE TRANSMISSION RATES
($/DTH)

Line No.	Path	GA IV 2010	2011	2012	2013	2014
1	G-AFT – Annual Firm Transportation					
2	Redwood Path – Core	$0.155	$~~0.277~~ 0.271	$~~0.297~~ 0.287	$~~0.320~~ 0.308	$~~0.326~~ 0.313
3	Baja Path – Core	$0.319	$~~0.277~~ 0.271	$~~0.297~~ 0.287	$~~0.320~~ 0.308	$~~0.326~~ 0.313
4	Redwood Path – Noncore	$0.294	$~~0.333~~ 0.338	$~~0.347~~ 0.357	$~~0.361~~ 0.374	$~~0.357~~ 0.372
5	Baja Path – Noncore	$0.319	$~~0.333~~ 0.338	$~~0.347~~ 0.357	$~~0.361~~ 0.374	$~~0.357~~ 0.372
6	Silverado and Mission Paths	$0.153	$0.148	$0.153	$0.161	$0.163
7	G-XF – Pipeline Expansion Firm Intrastate Transportation Service	$0.210	$~~0.195~~ 0.207	$~~0.188~~ 0.207	$~~0.178~~ 0.200	$~~0.168~~ 0.195

D. Backbone Level End-Use Rates (Ray Blatter)

Customers qualifying for backbone level service will continue to be exempt from paying the local transmission rate component in their end-user tariff. However, these customers will continue to be responsible for all other rate components in their end-user tariffs, including the CAC and the customer class charge. To the extent certain components of the customer class charge become the discounted deliveries. This discount adjustment results in Noncore local transmission rates that are $~~0.0013~~0.0007 per Dth higher than they would have otherwise been and Core local transmission rates that are $0.0008 per Dth higher than they would have otherwise been.

Table 11-9 presents PG&E's proposed 2011 through 2014 local transmission rates for Core and Noncore customers.

TABLE 11-9
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 PROPOSED LOCAL TRANSMISSION RATES
($/DTH)

Line No.	Customer Class	GA IV 2010(a)	2011	2012	2013	2014
1	Core	$0.369	$0.455	$0.484	$0.509	$~~0.548~~ 0.546
2	Noncore (Including Wholesale)	$0.160	$0.220	$0.233	$0.257	$~~0.273~~ 0.272

(a) The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for 2 of 5 of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement. (See Appendix 11A, Table 11A-13).

G. Transmission-Level Customer Access Charges (Ray Blatter)

1. Summary

PG&E proposes to update the Noncore transmission-level CAC to reflect the updated CAC revenue requirement developed in this case, and to make various other adjustments to the CAC rates. In the future, PG&E proposes that all CAC rate design matters be addressed in PG&E's BCAP proceedings, rather than GT&S rate cases. However, the CAC revenue requirement will continue to be determined in GT&S rate cases.

2. Background

The CAC recovers the costs of providing and maintaining a customer's service connection including the service line, regulator, meter and account services. Prior to Gas Accord I, PG&E's CAC revenue requirement was set in GRC proceedings and allocated to customer classes based on each class's customer marginal cost revenues in BCAPs. Beginning with Gas Accord I, CAC costs for transmission-level Noncore customers have been excluded from PG&E's GRC and BCAP proceedings.

TABLE 11A-1
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE END-USE CLASS AVERAGE RATES ($/DTH)(a)

Line No.		2010 Rates(b)	Proposed Rates 1/1/2011	$ Change(c)	% Change
1	**Core Retail Bundled Service(d)**				
2	Residential Non-CARE**/***	13.854	~~14.052~~	~~0.198~~	1.4%
			14.044	0.190	
3	Small Commercial Non-CARE**	11.925	~~12.117~~	~~0.192~~	~~1.6%~~
			12.110	0.185	1.5%
4	Large Commercial	9.747	~~9.917~~	~~0.169~~	1.7%
			9.910	0.163	
5	Uncompressed Core NGV	8.757	~~8.919~~	~~0.162~~	~~1.9%~~
			8.913	0.156	1.8%
6	Compressed Core NGV	17.864	17.949	0.084	0.5%
7	**Core Retail Transport Only(e)**				
8	Residential Non-CARE**/***	5.494	5.580	0.086	1.6%
9	Small Commercial	3.672	3.758	0.086	2.3%
10	Large Commercial	1.846	1.932	0.086	4.7%
11	Uncompressed Core NGV	0.962	1.048	0.086	8.9%
12	Compressed Core NGV	10.070	10.156	0.086	0.9%
13	**Noncore Retail Transportation Only(e)**				
14	Industrial – Distribution	1.505	1.559	0.054	3.6%
15	Industrial – Transmission	0.581	0.637	0.056	9.7%
16	Industrial – Backbone	0.371	0.364	(0.007)	-1.9%
17	Uncompressed Noncore NGV – Distribution	1.387	1.447	0.060	4.4%
18	Uncompressed Noncore NGV – Transmission	0.512	0.573	0.060	11.8%
19	Electric Generation – Distribution/Transmission	0.203	0.266	0.063	31.1%
20	Electric Generation – Backbone	0.043	0.036	(0.007)	-15.5%
21	**Wholesale Transportation Only(e)**				
22	Alpine Natural Gas	0.254	0.280	0.026	10.2%
23	Coalinga	0.246	0.288	0.042	17.1%
24	Island Energy	0.452	0.406	(0.046)	-10.2%
25	Palo Alto	0.179	0.239	0.060	33.4%
26	West Coast Gas - Castle	0.847	0.744	(0.104)	-12.2%
27	West Coast Gas - Mather D	0.784	0.835	0.052	6.6%
28	West Coast Gas - Mather T	0.255	0.307	0.052	20.3%

Notes:

a. Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

b. 2010 rates are based on PG&E's 2009 Annual Gas True-Up Filing (Advice Letter 2971-G and 2971-G-A), 2004 BCAP Decision D.05-06-029 and the 2010 backbone, local transmission, transmission level customer access, and bundled storage rates approved in Gas Accord IV D.07-09-045. In order to isolate the effect of PG&E's rate proposals in this filing, 2010 rates do not include $22 million in attrition as approved in PG&E's 2007 GRC Decision No. 07-03-044, Appendix A.

c. Dollar differences are due to rounding.

d. PG&E's bundled gas service is for Core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding, are included in end use rates paid by bundled Core customers. Bundled service also includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, and Core brokerage. An illustrative annual 2009 weighted average cost of gas (WACOG) of $6.96 as filed in Advice Letter 2791-G/2791-G-A, adjusted for intrastate backbone usage charges, is assumed in all present and proposed bundled Core rates. Core bundled rates also includes the cost of transportation and delivery of gas from the Citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

e. PG&E's transportation-only gas service is for Core and Noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

TABLE 11A-3
PACIFIC GAS AND ELECTRIC COMPANY
2010 RATE DETAIL BY END-USE CUSTOMER CLASS, INCLUDING ILLUSTRATIVE COMPONENTS ($/DTH)

Line No.		Core(a) Res	Core(a) Small Comm	Core(a) Large Comm	Core(a) Uncomp. NGV	Core(a) Comp. NGV	Noncore Transportation Industrial Dist	Noncore Transportation Industrial Trans	Noncore Transportation Industrial BB	Noncore Transportation Natural Gas Vehicle Dist	Noncore Transportation Natural Gas Vehicle Trans	Noncore Transportation Electric Gen D/T	Noncore Transportation Electric Gen BB
1	End-Use Transportation:												
2	Local Transmission and Rate Adders	0.455	0.455	0.455	0.455	0.455	0.220	0.220	0.000	0.220	0.220	0.220	0.000
3	Backbone Level End-Use Surcharge												
4	Distribution(b)	4.005	1.938	0.645	0.272	9.396	0.864	0.050	0.000	0.864	0.050	0.017	0.017
5	Mandated Customer Programs and Other Charges:												
6	Self Generation Incentive Program	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
7	CPUC Fee	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006
8	Balancing Accounts	0.451	0.366	0.081	0.025	0.025	0.006	0.002	0.002	0.006	0.002	0.002	0.002
9	Volumetric End-Use Rate	4.927	2.774	1.196	0.767	9.892	1.105	0.287	0.017	1.105	0.287	0.254	0.034
10	Customer/ Customer Access Charge(c)	0.000	0.539	0.048	0.017	0.000	0.072	0.017	0.015	0.078	0.021	0.012	0.003
11	Total End-Use Rate	4.927	3.313	1.244	0.785	9.892	1.177	0.305	0.032	1.183	0.309	0.266	0.036
12	Gas Public Purpose Program Surcharge	0.654	0.445	0.688	0.264	0.264	0.382	0.332	0.332	0.264	0.264	0.000	0.000
13	Total Rate	5.580	3.758	1.932	1.048	10.156	1.559	0.637	0.364	1.447	0.573	0.266	0.036
14	Procurement Charges for Core Bundled Customers:												
15	Storage	0.1759	0.1624	0.1061	0.1022	0.102							
16	Backbone Capacity	~~0.2535~~	~~0.2244~~	~~0.1242~~	~~0.0780~~	0.0000							
		0.251	0.222	0.123	0.077								
17	Backbone Usage	~~0.1106~~	~~0.111~~	~~0.111~~	~~0.111~~	~~0.111~~							
		0.105	0.105	0.105	0.105	0.105							
18	WACOG(d)	6.9645	6.9645	6.9645	6.9645	6.9645							
19	Interstate Capacity and Other	~~0.9675~~	~~0.8970~~	~~0.6791~~	~~0.6154~~	~~0.6154~~							
		0.967	0.897	0.679	0.615	0.615							
20	Total Core Procurement	~~8.4720~~	~~8.359~~	~~7.985~~	~~7.871~~	~~7.793~~							
		8.4640	8.351	7.978	7.864	7.787							
21	Total Core Bundled Rates	~~14.052~~	~~12.117~~	~~9.917~~	~~8.919~~	~~17.949~~							
		14.044	12.109	9.910	8.913	17.943							

Line No.		Wholesale Transportation Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
1	End-Use Transportation:							
2	Local Transmission and Rate Adders	0.220	0.220	0.220	0.220	0.220	0.220	0.220
3	Backbone Level End-Use Surcharge							
4	Distribution(b)	0.000	0.000	0.000	0.000	0.382	0.528	0.000
5	Mandated Customer Programs and Other Charges:							
6	Self Generation Incentive Program	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	CPUC Fee	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Balancing Accounts	0.002	0.002	0.002	0.002	0.003	0.003	0.002
9	Volumetric End-Use Rate	0.222	0.222	0.222	0.222	0.605	0.751	0.222
10	Customer/ Customer Access Charge(c)	0.058	0.066	0.184	0.017	0.139	0.085	0.085
11	Total End-Use Rate	0.280	0.288	0.406	0.239	0.744	0.835	0.307
12	Gas Public Purpose Program Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	Total Rate	0.280	0.288	0.406	0.239	0.744	0.835	0.307

Notes:

a. Class average rates reflect load shape for bundled Core.
b. Distribution rates represent the annual class average.
c. Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.
d. Reflects the annual average 2009 WACOG of as filed in Advice Letter 2791-G/2791-G-A.
e. Dollar differences are due to rounding.

TABLE 11A-4
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	4.337	~~8.195~~ 8.005	~~9.054~~ 8.738	~~9.716~~ 9.360	~~10.017~~ 9.607
3	Usage Charge	($/dth)	0.012	0.008	0.008	0.008	0.008
4	Total	($/dth @ Full	0.155	~~0.277~~	~~0.297~~	~~0.320~~	~~0.326~~
5		Contract)		0.271	0.287	0.308	0.313
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	9.232	~~8.195~~ 8.005	~~9.054~~ 8.738	~~9.716~~ 9.360	~~10.017~~ 9.607
8	Usage Charge	($/dth)	0.015	0.008	0.008	0.008	0.008
9	Total	($/dth @ Full	0.319	~~0.277~~	~~0.297~~	~~0.320~~	~~0.326~~
10		Contract)		0.271	0.287	0.308	0.313
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	8.733	~~9.899~~ 10.057	~~10.613~~ 10.923	~~11.014~~ 11.387	~~10.973~~ 11.440
13	Usage Charge	($/dth)	0.007	0.007	~~0.007~~ 0.008	0.008	0.008
14	Total	($/dth @ Full	0.294	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
15		Contract)		0.338	0.357	0.374	0.372
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	9.232	~~9.899~~ 10.057	~~10.613~~ 10.923	~~11.014~~ 11.387	~~10.973~~ 11.440
18	Usage Charge	($/dth)	0.015	0.007	~~0.007~~ 0.008	0.008	0.008
19	Total	($/dth @ Full	0.319	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
20		Contract)		0.338	0.357	0.374	0.372
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	4.483	~~4.417~~ 4.412	~~4.569~~ 4.562	~~4.823~~ 4.821	~~4.868~~ 4.870
23	Usage Charge	($/dth)	0.006	0.003	0.003	0.003	0.003
24	Total	($/dth @ Full	0.153	0.148	0.153	0.161	0.163
25		Contract)					

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-5
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	3.329	~~5.783~~	~~6.106~~	~~6.498~~	~~6.624~~
				5.727	6.002	6.391	6.498
3	Usage Charge	($/dth)	0.046	~~0.087~~	~~0.096~~	~~0.106~~	~~0.108~~
				0.083	0.089	0.098	0.099
4	Total	($/dth @ Full	0.155	~~0.277~~	~~0.297~~	~~0.320~~	~~0.326~~
5		Contract)		0.271	0.287	0.308	0.313
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	7.004	~~5.783~~	~~6.106~~	~~6.498~~	~~6.624~~
				5.727	6.002	6.391	6.498
8	Usage Charge	($/dth)	0.089	~~0.087~~	~~0.096~~	~~0.106~~	~~0.108~~
				0.083	0.089	0.098	0.099
9	Total	($/dth @ Full	0.319	~~0.277~~	~~0.297~~	~~0.320~~	~~0.326~~
10		Contract)		0.271	0.287	0.308	0.313
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	5.070	~~6.574~~	~~6.894~~	~~7.224~~	~~7.234~~
				6.625	7.007	7.357	7.392
13	Usage Charge	($/dth)	0.127	~~0.117~~	~~0.120~~	~~0.124~~	~~0.119~~
				0.121	0.127	0.132	0.129
14	Total	($/dth @ Full	0.294	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
15		Contract)		0.338	0.357	0.374	0.372
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	7.004	~~6.574~~	~~6.894~~	~~7.224~~	~~7.234~~
				6.625	7.007	7.357	7.392
18	Usage Charge	($/dth)	0.089	~~0.117~~	~~0.120~~	~~0.124~~	~~0.119~~
				0.121	0.127	0.132	0.129
19	Total	($/dth @ Full	0.319	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
20		Contract)		0.338	0.357	0.374	0.372
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	3.084	~~3.051~~	~~3.146~~	~~3.313~~	~~3.364~~
				3.049	3.144	3.316	3.366
23	Usage Charge	($/dth)	0.052	0.048	0.050	0.053	0.052
24	Total	($/dth @ Full	0.153	0.148	0.153	0.161	0.163
25		Contract)					

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-6
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
SEASONAL RATES (SFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	10.480	~~9.8344~~	~~10.8644~~	~~11.659~~	~~12.0201~~
				9.606	10.486	11.232	11.529
3	Usage Charge	($/dth)	0.008	~~0.0094~~	~~0.0094~~	~~0.0095~~	~~0.0096~~
				0.009	0.009	0.010	0.010
4	Total	($/dth @ Full	0.353	~~0.3327~~	~~0.35604~~	~~0.3834~~	~~0.39127~~
5		Contract)		0.326	0.344	0.370	0.376
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	~~11.0784~~	~~9.8344~~	~~10.8644~~	~~11.659~~	~~12.0201~~
			11.078	9.606	10.486	11.232	11.529
8	Usage Charge	($/dth)	~~0.0183~~	~~0.0094~~	~~0.0094~~	~~0.0095~~	~~0.0096~~
			0.018	0.009	0.009	0.010	0.010
9	Total	($/dth @ Full	0.3825	0.3327	0.3560	0.3834	0.3913
10		Contract)					
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	10.480	~~11.879~~	~~12.736~~	~~13.217~~	~~13.168~~
				12.068	13.107	13.664	13.728
13	Usage Charge	($/dth)	0.008	~~0.004~~	~~0.004~~	~~0.004~~	~~0.004~~
				0.009	0.009	0.009	0.009
14	Total	($/dth @ Full	0.353	~~0.399~~	~~0.416~~	~~0.434~~	~~0.428~~
15		Contract)		0.406	0.428	0.448	0.446
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	11.078	~~11.879~~	~~12.736~~	~~13.217~~	~~13.168~~
				12.068	13.107	13.664	13.728
18	Usage Charge	($/dth)	0.018	0.004	0.004	0.004	0.004
19	Total	($/dth @ Full	0.383	0.399	0.416	0.434	0.428
20		Contract)					
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	5.379	~~5.301~~	~~5.483~~	~~5.788~~	~~5.841~~
				5.294	5.474	5.785	5.844
23	Usage Charge	($/dth)	0.007	0.003	0.003	0.003	0.004
24	Total	($/dth @ Full	0.184	~~0.178~~	~~0.184~~	0.194	0.196
25		Contract)		0.177	0.183		

Notes:

a. Firm Seasonal rates are 120 percent of Firm Annual rates.
b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
c. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
d. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.
e. Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.
f. Dollar differences are due to rounding.

TABLE 11A-7
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
SEASONAL RATES (SFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	6.084	~~6.9399~~	~~7.3266~~	~~7.7981~~	~~7.9487~~
				6.872	7.202	7.669	7.798
3	Usage Charge	($/dth)	~~0.1528~~	~~0.1046~~	~~0.1152~~	~~0.1271~~	~~0.1299~~
			0.153	0.100	0.107	0.118	0.119
4	Total	($/dth @ Full	~~0.3528~~	~~0.3327~~	~~0.3560~~	~~0.3834~~	~~0.3913~~
5		Contract)	0.353	0.326	0.344	0.370	0.376
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	~~8.4044~~	~~6.9399~~	~~7.3266~~	~~7.7981~~	~~7.9487~~
			8.404	6.872	7.202	7.669	7.798
8	Usage Charge	($/dth)	~~0.1063~~	~~0.1046~~	~~0.1152~~	~~0.1271~~	~~0.1299~~
			0.106	0.100	0.107	0.118	0.119
9	Total	($/dth @ Full	~~0.3826~~	~~0.3327~~	~~0.3560~~	~~0.3834~~	~~0.3913~~
10		Contract)	0.383	0.326	0.344	0.370	0.376
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	6.084	~~7.889~~	~~8.272~~	~~8.669~~	~~8.681~~
				7.950	8.408	8.828	8.871
13	Usage Charge	($/dth)	0.153	~~0.140~~	~~0.144~~	~~0.149~~	~~0.143~~
				0.145	0.152	0.158	0.155
14	Total	($/dth @ Full	0.353	~~0.399~~	~~0.416~~	~~0.434~~	~~0.428~~
15		Contract)		0.406	0.428	0.448	0.446
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	8.404	~~7.889~~	~~8.272~~	~~8.669~~	~~8.681~~
				7.950	8.408	8.828	8.871
18	Usage Charge	($/dth)	0.106	~~0.140~~	~~0.144~~	~~0.149~~	~~0.143~~
				0.145	0.152	0.158	0.155
19	Total	($/dth @ Full	0.383	~~0.399~~	~~0.416~~	~~0.434~~	~~0.428~~
20		Contract)		0.406	0.428	0.448	0.446
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	3.701	~~3.661~~	~~3.776~~	~~3.976~~	~~4.037~~
				3.659	3.773	3.979	4.039
23	Usage Charge	($/dth)	0.062	0.057	~~0.060~~	0.063	0.063
					0.059		
24	Total	($/dth @ Full	0.184	~~0.178~~	~~0.184~~	0.194	0.196
25		Contract)		0.177	0.183		

Notes:

a. Firm Seasonal rates are 120 percent of Firm Annual rates.
b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
c. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
d. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.
e. Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.
f. Dollar differences are due to rounding.

TABLE 11A-8
PACIFIC GAS AND ELECTRIC COMPANY
AS-AVAILABLE BACKBONE TRANSPORTATION
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Usage Charge	($/dth)	0.353	~~0.333~~ 0.326	~~0.356~~ 0.344	~~0.383~~ 0.370	~~0.391~~ 0.376
3	**Baja Path - Core**						
4	Usage Charge	($/dth)	0.383	~~0.333~~ 0.326	~~0.356~~ 0.344	~~0.383~~ 0.370	~~0.391~~ 0.376
5	**Redwood Path - Noncore**						
6	Usage Charge	($/dth)	0.353	~~0.399~~ 0.406	~~0.416~~ 0.428	~~0.434~~ 0.448	~~0.428~~ 0.446
7	**Baja Path - Noncore**						
8	Usage Charge	($/dth)	0.383	~~0.399~~ 0.406	~~0.416~~ 0.428	~~0.434~~ 0.448	~~0.428~~ 0.446
9	**Silverado Path**						
10	Usage Charge	($/dth)	0.184	0.178	~~0.184~~ 0.183	0.194	0.196
11	**Mission Path**						
12	Usage Charge	($/dth)	0.000	0.000	0.000	0.000	0.000

Notes:

a. As-Available rates are 120 percent of Firm Annual rates.

b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c. Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-9
PACIFIC GAS AND ELECTRIC COMPANY
BACKBONE TRANSPORTATION
ANNUAL RATES (AFT-OFF)
OFF-SYSTEM DELIVERIES

Line No.			GA IV 2010	2011	2012	2013	2014
1	**SFV Rate Design**						
2	**Redwood, Silverado and Mission Paths Off-System**						
3	Reservation Charge	($/dth/mo)	8.733	~~9.899~~ 10.057	~~10.613~~ 10.923	~~11.014~~ 11.387	~~10.973~~ 11.440
4	Usage Charge	($/dth)	0.007	0.007	~~0.007~~ 0.008	0.008	0.008
5	Total	($/dth @ Full	0.294	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
6		Contract)		0.338	0.357	0.374	0.372
7	**Baja Path Off-System**						
8	Reservation Charge	($/dth/mo)	9.232	~~9.899~~ 10.057	~~10.613~~ 10.923	~~11.014~~ 11.387	~~10.973~~ 11.440
9	Usage Charge	($/dth)	0.015	0.007	~~0.007~~ 0.008	0.008	0.008
10	Total	($/dth @ Full	0.319	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
11		Contract)		0.338	0.357	0.374	0.372
12	**MFV Rate Design**						
13	**Redwood, Silverado and Mission Paths Off-System**						
14	Reservation Charge	($/dth/mo)	5.070	~~6.574~~ 6.625	~~6.894~~ 7.007	~~7.224~~ 7.357	~~7.234~~ 7.392
15	Usage Charge	($/dth)	0.127	~~0.117~~ 0.121	~~0.120~~ 0.127	~~0.124~~ 0.132	~~0.119~~ 0.129
16	Total	($/dth @ Full	0.294	~~0.333~~	~~0.347~~	~~0.361~~	~~0.357~~
17		Contract)		0.338	0.357	0.374	0.372
18	**Baja Path Off-System**						
19	Reservation Charge	($/dth/mo)	7.004	~~6.574~~ 6.625	~~6.894~~ 7.007	~~7.224~~ 7.357	~~7.234~~ 7.392
20	Usage Charge	($/dth)	0.089	~~0.117~~ 0.121	~~0.120~~ 0.127	~~0.124~~ 0.132	~~0.119~~ 0.129
21	Total	($/dth @ Full	0.319	~~0.333~~ 0.338	~~0.347~~ 0.357	~~0.361~~ 0.374	~~0.357~~ 0.372
22	**As-Available Service**						
23	**Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore**						
24	Usage Charge	($/dth)	0.353	~~0.399~~ 0.406	~~0.416~~ 0.428	~~0.434~~ 0.448	~~0.428~~ 0.446
25	**Mission Paths (From On-System Storage) Off-System**						
26	Usage Charge	($/dth)	0.000	0.000	0.000	0.000	0.000
27	**Baja Path Off-System - Noncore**						
28	Usage Charge	($/dth)	0.383	~~0.399~~ 0.406	~~0.416~~ 0.428	~~0.434~~ 0.448	~~0.4283~~ 0.446

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

d. Dollar differences are due to rounding.

TABLE 11A-10
PACIFIC GAS AND ELECTRIC COMPANY
FIRM TRANSPORTATION
EXPANSION SHIPPERS – ANNUAL RATES (G-XF)
SFV RATE DESIGN

Line No.			GA IV 2010	2011	2012	2013	2014
1	**SFV Rate Design**						
2	Reservation Charge	($/dth/mo)	6.318	~~5.873~~	~~5.680~~	~~5.363~~	~~5.056~~
				6.241	6.257	6.036	5.885
3	Usage Charge	($/dth)	0.002	0.002	0.002	0.002	0.002
4	Total	($/dth @ Full	0.210	~~0.195~~	~~0.188~~	~~0.178~~	~~0.168~~
5		Contract)		0.207	0.207	0.200	0.195

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d. Dollar differences are due to rounding.

TABLE 11A-11
PACIFIC GAS AND ELECTRIC COMPANY
STORAGE SERVICES

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Core Firm Storage (G-CFS)**						
2	Reservation Charge	($/dth/mo)	0.109	0.127	0.131	~~0.134~~ 0.135	0.138
3	**Standard Firm Storage (G-SFS)**						
4	Reservation Charge	($/dth/mo)	0.135	0.251	0.253	~~0.262~~ 0.258	~~0.262~~ 0.260
5	**Negotiated Firm Storage (G-NFS)**						
6	Injection	($/dth/d)	15.634	6.309	6.360	~~6.567~~ 6.467	~~6.573~~ 6.518
7	Inventory	($/dth)	1.621	3.015	3.039	~~3.138~~ 3.090	~~3.141~~ 3.114
8	Withdrawal	($/dth/d)	11.787	21.845	22.021	~~22.736~~ 22.389	~~22.758~~ 22.566
9	**Negotiated As-Available Storage (G-NAS) - Maximum Rate**						
10	Injection	($/dth/d)	15.634	6.309	6.360	~~6.567~~ 6.467	~~6.573~~ 6.518
11	Withdrawal	($/dth/d)	11.787	21.845	22.021	~~22.736~~ 22.389	~~22.758~~ 22.566
12	**Market Center Services (Parking and Lending Services)**						
13	Maximum Daily Charge ($/Dth/d)		0.970	1.131	1.150	~~1.187~~ 1.170	~~1.194~~ 1.185
14	Minimum Rate (per transaction)		~~$ 57.00~~ 57.000	57.000	57.000	57.000	57.000

Notes:

a. Rates for storage services are based on the costs of storage injection, inventory and withdrawal.
b. Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.
c. Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.
d. Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.
e. Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g., inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.
f. Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.
g. The maximum charge for parking and lending is based on the annual cost of cycling 1 Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.
h. Gas Storage shrinkage will be applied in-kind on storage injections.
i. Dollar differences are due to rounding.

TABLE 11A-13
PACIFIC GAS AND ELECTRIC COMPANY
LOCAL TRANSMISSION RATES ($/DTH)

Line No.		GA IV 2010	2011	2012	2013	2014
1	**Base Rates:**					
2	Core Retail	0.337	0.455	0.484	0.509	~~0.548~~ 0.546
3	Noncore Retail and Wholesale	0.146	0.220	0.233	0.257	~~0.273~~ 0.272
4	**Rate Adders:**					
5	Core					
6	Line 138 (16 miles of 30"pipe)	~~0.0173~~ 0.017	0.000	0.000	0.000	0.000
7	Line 108 (11 miles of 24" pipe)	~~0.0152~~ 0.015	0.000	0.000	0.000	0.000
8	Line 406 (15 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
9	Line 407 (4 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
10	Line 407 (8 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
11	Total	~~0.0325~~ 0.033	0.000	0.000	0.000	0.000
12	Noncore Retail & Wholesale					
13	Line 138 (16 miles of 30"pipe)	~~0.0075~~ 0.008	0.000	0.000	0.000	0.000
14	Line 108 (11 miles of 24" pipe)	~~0.0066~~ 0.007	0.000	0.000	0.000	0.000
15	Line 406 (15 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
16	Line 407 (4 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
17	Line 407 (8 miles of 30" pipe)	~~0.0000~~ 0.000	0.000	0.000	0.000	0.000
18	Total	~~0.0141~~ 0.014	0.000	0.000	0.000	0.000
19	**Total Base plus Adder:**					
20	Core Retail	0.369	0.455	0.484	0.509	~~0.548~~ 0.546
21	Noncore Retail and Wholesale	0.160	0.220	0.233	0.257	~~0.273~~ 0.272

Notes:

a. The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for two of five of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX 11B
TRADITIONAL BACKBONE RATE CALCULATION

A. Scope and Purpose (Carl Orr)

As discussed in Chapter 1, "Introduction and Policy," and Chapter 11, "Cost Allocation and Rate Design," Pacific Gas and Electric Company (PG&E or the Company) is proposing two significant changes to its backbone rate design. First, PG&E is proposing to equalize the Core Redwood and Core Baja rates, and the Noncore Redwood (excluding Schedule G-XF) and Noncore Baja rates. Second, PG&E is proposing a demand based backbone rate design rather than the traditional system average load factor based rate design. This appendix provides a traditional backbone rate calculation—without equalization of any rates, and employing a system average load factor—as a point of reference for PG&E's proposals in Chapter 11.

B. Background (Carl Orr)

As explained in Chapter 2, "Gas Transmission Facilities and Services," PG&E provides backbone transmission service on four backbone paths: Redwood; Baja; Silverado; and Mission. For rate design purposes, PG&E further divides the Redwood path into three sub-paths: Core Redwood; Noncore Redwood; and Schedule G-XF. The rate design process also disregards the Mission path. No costs are allocated to the Mission path because the Mission as-available rate is zero. Although the Mission firm rate is not zero (it is set equal to the Silverado firm rate), no customers are forecasted to take Mission firm service.

Under traditional utility rate design, the allocated costs for each backbone path would be divided by the adopted throughput or demand for the path to get the path rate. However, PG&E forecasts total end-use demand, not path-by-path throughputs. Developing end-use demand projections is a complex process in its own right. To take the next step and forecast which supply sources and backbone paths will serve that demand would be even more difficult.[1] Therefore, since the beginning of the Gas Accord structure in 1998, PG&E has designed backbone rates based on a system average backbone load factor. The system average load factor is calculated as total backbone throughput divided by total backbone capacity, plus various adjustments. Thus, instead of dividing allocated costs by a forecast of path demand, PG&E divides allocated costs by the product of the path capacity and the system average load factor:

$$\text{Path Rate} = \frac{\text{Allocated Path Costs (\$ '000)}}{\text{Path Capacity (MDth/d)} \times \text{System Average Load Factor (\%)} \times \text{365 d}}$$

In effect, this methodology assumes that all paths are used proportionally to serve demand on PG&E's system. Another way of thinking about the methodology is it *de-averages* the numerator (costs) of the backbone rate calculation by path, but *averages* the denominator (throughput).

The remainder of this appendix describes the system average backbone load factor calculation (Section C) and the traditional backbone cost allocation and rate design employing the backbone load factor (Section D).

C. Calculation of System Average Backbone Load Factor (Carl Orr)

1. Introduction

This section combines the various gas demand forecasts from Chapter ~~11~~10 and the various backbone capacities from Chapter 2 to develop the system average backbone load factor traditionally used to calculate PG&E's backbone rates. This section also provides details of several load factor adjustments that are necessary to ensure that load factor based backbone rates fully collect, but do not over-collect, adopted backbone costs at adopted demand levels.

2. Load Factor Calculation

Table 11B-1 shows the backbone load factor calculation for traditional backbone rate design for 2011 through 2014.

[1] As explained in Chapter 11, PG&E is proposing a demand based backbone rate design because equalization of the rates for all Core service, and for substantially all Noncore service (excluding G-XF and Silverado), lends itself to use of the Core and Noncore demand forecasts as path throughput forecasts.

TABLE 11B-1
PACIFIC GAS AND ELECTRIC COMPANY
SYSTEM AVERAGE BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN

		2011	2012	2013	2014
1	**Backbone Demand (MDth/d)**				
2	Core	793	~~800~~ 802	805	802
3	Core distribution shrinkage	23	23	23	23
4	Noncore industrial	465	~~467~~ 468	469	470
5	Wholesale	10	10	10	10
6	Electric generation	~~508~~ 509	~~531~~ 533	~~521~~ 522	~~542~~ 543
7	Cogeneration	201	~~201~~ 202	201	201
8	Subtotal, on-system	~~2,000~~ 2,001	~~2,032~~ 2,038	~~2,030~~ 2,031	~~2,049~~ 2,050
9	G-XF off-system	86	80	80	80
10	Non-G-XF off-system (full-rate-equivalent throughput) **(a)**	~~30~~ 29	~~30~~ 29	~~31~~ 30	~~33~~ 30
11	Subtotal, off-system	116	~~111~~ 109	~~112~~ 110	~~113~~ 111
12	TOTAL	2,117	~~2,143~~ 2,148	~~2,142~~ 2,141	~~2,162~~ 2,160
13	Remove G-XF contracts	(92)	(86)	(86)	(86)
14	Adjust for Pilkington Baja on-system discount **(b)**	(1)	(1)	(1)	(1)
15	Adjust for G-AA, G-SFT, and G-NFT premiums **(c)**	55	~~32~~ 34	32	36
16	Adjust for reservation charges for un-used firm contracts **(d)**	48	49	49	49
17	Adjust for disproportionate path flows **(e)**	~~(23)~~ (39)	~~11~~ (19)	~~51~~ 17	~~67~~ 28
18	Subtotal, adjustments	~~(12)~~ (28)	~~6~~ (23)	~~44~~ 11	~~65~~ 26
19	TOTAL, ADJUSTED	~~2,105~~ **2,089**	~~2,148~~ **2,125**	~~2,187~~ **2,152**	~~2,227~~ **2,186**
20	**Backbone Capacity (MDth/d @ Delivery Point)**				
21	Redwood Line 401	~~1,024~~ 1,015	~~1,024~~ 1,015	~~1,024~~ 1,015	~~1,024~~ 1,015
22	Redwood Line 400	~~1,042~~ 1,033	~~1,042~~ 1,033	~~1,042~~ 1,033	~~1,042~~ 1,033
23	Baja Line 300	~~1,068~~ 1,040	1,068	1,068	1,068
24	Silverado "capacity"	~~195~~ 193	~~191~~ 192	~~187~~ 189	~~184~~ 186
25	TOTAL	~~3,329~~ 3,282	~~3,325~~ 3,309	~~3,321~~ 3,306	~~3,318~~ 3,303
26	Remove G-XF contracts	(92)	(86)	(86)	(86)
27	Remove SMUD equity capacity, Line 401	~~(44)~~ (43)	~~(44)~~ (43)	~~(44)~~ (43)	~~(44)~~ (43)
28	Remove SMUD equity capacity, Line 300	(41)	(41)	(41)	(41)
29	Subtotal, adjustments	~~(177)~~ (176)	~~(171)~~ (170)	~~(171)~~ (170)	~~(171)~~ (170)
30	TOTAL, ADJUSTED	~~3,152~~ **3,106**	~~3,154~~ **3,139**	~~3,151~~ **3,136**	~~3,147~~ **3,133**
31	Memo: Silverado flow forecast	130	130	130	130
32	**Backbone Load Factor**	~~66.78%~~ **67.26%**	~~68.11%~~ **67.69%**	~~69.40%~~ **68.62%**	~~70.76%~~ **69.78%**

The on-system demands in Lines 1 through 8 of Table 11B-1 are taken from Chapter ~~11~~10, except that Core distribution shrinkage (line 3) is added, based on a shrinkage rate of 2.9 percent. Off-system throughput is shown on lines 9 through 11. This forecast includes non-G-XF off-system throughput (expressed as full-rate-equivalent throughput), which is discussed further in the next section. Total throughput is shown on line 12. Various throughput adjustments are shown on lines 13 through 18, which are discussed in detail in the next section. Line 19 shows total adjusted throughput.

The backbone throughput represented on lines 1 through 19 of Table 11B-1 excludes Mission path throughput. The Mission path is used

TABLE 11B-2
PACIFIC GAS AND ELECTRIC COMPANY
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN

		2011	2012	2013	2014
1	**(a) Calculate full rate equivalent non-G-XF off-system throughput**				
2	Forecasted revenues ($ '000/yr)	$3,277	$3,277	$3,277	$3,277
3	Redwood G-AFT rate ($/Dth)	~~$0.299~~	~~$0.295~~	~~$0.285~~	~~$0.275~~
		$0.305	$0.309	$0.302	$0.296
4	Full rate equivalent throughput (MDth/d)	~~**30**~~	~~**30**~~	~~**31**~~	~~**33**~~
		29	**29**	**30**	**30**
5	**(b) Adjust for Pilkington Baja on-system discount**				
6	Throughput adjustment (MDth/d)	**(1)**	**(1)**	**(1)**	**(1)**
7	(Note: The details of this adjustment are confidential.)				
8	**(c) Adjust for G-AA, G-SFT, and G-NFT premiums**				
9	G-AA throughput - Core (MDth/d)	3	3	3	3
10	G-AA throughput - Noncore (MDth/d)				
11	Total on-system throughput	~~2,000~~	~~2,032~~	~~2,030~~	~~2,049~~
		2,001	2,038	2,031	2,050
12	EAD throughput	8	0	0	0
13	G-XF on-system throughput	5	5	5	5
14	Firm throughput excl EAD and G-XF	1,902	1,918	1,918	1,918
15	G-AA throughput, Core	3	3	3	3
16	G-AA throughput, Noncore (determined residually)	~~82~~	~~106~~	~~104~~	~~123~~
		83	112	105	124
17	G-SFT throughput - Core				
18	Core G-SFT MDQ (annualized MDth/d)	72	55	55	55
19	Core G-SFT utilization rate	96.4%	96.4%	96.4%	96.4%
20	Core G-SFT throughput (MDth/d)	69	53	53	53
21	G-SFT and G-NFT throughput - Noncore				
22	Noncore G-SFT and G-NFT MDQ (annualized MDth/d)	126	0	0	0
23	Noncore G-SFT and G-NFT average utilization rate	96.2%	96.2%	96.2%	96.2%
24	Noncore G-SFT and G-NFT throughput (MDth/d)	121	0	0	0
25	TOTAL (MDth/d)	276	~~162~~	~~160~~	~~179~~
			168	161	180
26	Rate premium	20%	20%	20%	20%
27	Premium adjustment (MDth/d)	**55**	~~**32**~~	**32**	**36**
			34		
28	**(d) Adjust for reservation charges for unused firm contracts**				
29	Total firm contract MDQ excl EAD and G-XF (MDth/d)	1,974	1,991	1,991	1,991
30	Average firm contract utilization rate excl G-XF and EAD	96.3%	96.3%	96.3%	96.3%
31	Unused firm MDQ (MDth/d)	73	73	73	73
32	Average reservation portion of MFV rate	66.7%	66.5%	66.3%	66.7%
33	Unused firm contract adjustment (MDth/d)	**48**	**49**	**49**	**49**

TABLE 11B-2
PACIFIC GAS AND ELECTRIC COMPANY
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN
(CONTINUED)

		2011	2012	2013	2014
34	**(e) Adjust for disproportionate path flows**				
35	Redwood Core capacity (MDth/d)	616	616	616	616
36	Throughput at load factor (MDth/d)	~~411~~ 414	~~419~~ 417	~~427~~ 422	~~436~~ 430
37	Expected Redwood Core utilization rate (incl brokering)	98.7%	98.7%	98.7%	98.7%
38	Expected Redwood Core throughput (MDth/d)	608	608	608	608
39	Throughput shift to Redwood Core path (MDth/d)	~~197~~ 194	~~188~~ 191	~~180~~ 185	~~172~~ 178
40	Redwood Core rate as percent of system average rate	~~62.9%~~ 58.0%	~~66.5%~~ 59.2%	~~66.1%~~ 58.1%	~~68.3%~~ 59.0%
41	Percent difference relative to system average rate	~~-37.1%~~ -42.0%	~~-33.5%~~ -40.8%	~~-33.9%~~ -41.9%	~~-31.7%~~ -41.0%
42	Throughput adjustment (MDth/d)	~~(73)~~ (81)	~~(63)~~ (78)	~~(61)~~ (78)	~~(54)~~ (73)
43	Baja capacity (MDth/d, excl SMUD equity)	~~1,027~~ 999	1,027	1,027	1,027
44	Throughput at load factor (MDth/d)	~~686~~ 672	~~700~~ 695	~~713~~ 705	~~727~~ 717
45	Expected Baja utilization rate (incl brokering)	83.5%	83.5%	83.5%	83.5%
46	Expected Baja throughput (MDth/d)	~~858~~ 834	858	858	858
47	Throughput shift to Baja path (MDth/d)	~~172~~ 162	~~158~~ 162	~~145~~ 153	~~131~~ 141
48	Baja rate as percent of system average rate	~~124.5%~~ 126.0%	~~128.7%~~ 128.4%	~~136.8%~~ 136.5%	~~139.0%~~ 138.4%
49	Percent difference relative to system average rate	~~24.5%~~ 26.0%	~~28.7%~~ 28.4%	~~36.8%~~ 36.5%	~~39.0%~~ 38.4%
50	Throughput adjustment (MDth/d)	42	~~45~~ 46	~~53~~ 56	~~51~~ 54
51	Redwood Noncore capacity (MDth/d; excl G-XF and SMUD equity)	~~1,315~~ 1,298	~~1,321~~ 1,304	~~1,321~~ 1,304	~~1,321~~ 1,304
52	Throughput at load factor (MDth/d)	~~878~~ 873	~~900~~ 883	~~917~~ 895	~~935~~ 910
53	Expected Redwood Noncore throughput (determined residually, MDth/d)	~~430~~ 453	~~462~~ 466	~~461~~ 460	~~481~~ 479
54	Throughput shift to Redwood Noncore path (MDth/d)	~~(448)~~ (420)	~~(438)~~ (416)	~~(455)~~ (435)	~~(454)~~ (431)
55	Redwood Noncore rate as percent of system average rate	~~98.2%~~ 99.9%	~~93.3%~~ 96.8%	~~87.2%~~ 91.0%	~~84.4%~~ 89.1%
56	Percent difference relative to system average rate	~~-1.8%~~ -0.1%	~~-6.7%~~ -3.2%	~~-12.8%~~ -9.0%	~~-15.6%~~ -10.9%
57	Throughput adjustment (MDth/d)	~~8~~ 0	~~29~~ 13	~~58~~ 39	~~71~~ 47
58	Total throughput adjustment (MDth/d)	~~(23)~~ **(39)**	~~11~~ **(19)**	~~51~~ **17**	~~67~~ **28**
59	**Backbone Rate Inputs (G-AFT, $/Dth)**				
60	System average rate (excl Silverado and G-XF)	~~$0.304~~ $0.306	~~$0.316~~ $0.319	~~$0.327~~ $0.332	~~$0.326~~ $0.332
61	Redwood Core rate	~~$0.191~~ $0.177	~~$0.210~~ $0.189	~~$0.216~~ $0.193	~~$0.223~~ $0.196
62	Redwood Noncore rate	~~$0.299~~ $0.305	~~$0.295~~ $0.309	~~$0.285~~ $0.302	~~$0.275~~ $0.296
63	Baja rate	~~$0.378~~ $0.385	~~$0.407~~ $0.410	~~$0.448~~ $0.453	~~$0.453~~ $0.460

To understand the various throughput adjustments, it is necessary to understand how the system average backbone load factor is used in the traditional backbone rate setting process. It is used to calculate annual firm transmission (G-AFT) rates. All other backbone rates or rate caps—for seasonal firm, negotiated firm, as-available, and negotiated as-available services—are derived from multiples of the annual firm rate. For example, the as-available rate for a given path is 120 percent of the annual firm rate for that path. Thus, the "raw" system average load factor must be adjusted for transmission services that PG&E expects to provide at rates above or below the annual firm rate.

In addition, to the extent the throughputs on PG&E's various backbone paths are expected to deviate from proportional throughputs to SMUD under an equity ownership arrangement have been excluded from the cost of service.

TABLE 11B-3
PACIFIC GAS AND ELECTRIC COMPANY
2011 FIRM CAPACITIES FOR ALLOCATING COSTS TO BACKBONE PATHS (EXCLUDES SMUD EQUITY INTERESTS) – TRADITIONAL BACKBONE RATE DESIGN
(MDth/d)

Line No.	Rate Path	Redwood Core Vintage	Other Redwood (Noncore)	Line 401 (Included in Other Redwood)	Baja	Common
1	Redwood – Core Vintage	615.60				615.60
2	Redwood		~~1,314.74~~ 1,297.97			~~1,314.74~~ 1,297.97
3	L401 Non G-XF			~~888.31~~ 880.17		
4	L401 G-XF			91.83		
5	Baja				~~1,027.23~~ 999.01	~~1,027.23~~ 999.01
6	Silverado/Mission		~~38.94~~ 38.65		~~38.94~~ 38.65	~~194.68~~ 193.27
7	Total	615.60	~~1,353.68~~ 1,336.62	~~980.15~~ 972.00	~~1,066.16~~ 1,037.66	~~3,125.25~~ 3,105.84

Table 11B-4 summarizes the costs allocated to each backbone transmission path based on the firm backbone capacities shown in Table 11B-3.

TABLE 11B-4
PACIFIC GAS AND ELECTRIC COMPANY
2011 COST ALLOCATION TO BACKBONE PATHS (EXCLUDES SMUD EQUITY INTERESTS) – TRADITIONAL BACKBONE RATE DESIGN
($000)

Line No.	Rate Path	Redwood Core Vintage	Other Redwood (Noncore)	Line 401 (Included in Other Redwood)	Baja	Common	Total Backbone
1	Redwood – Core Vintage	$~~18,335~~ 16,270				$~~10,349~~ 10,503	$~~28,683~~ 26,773
2	Redwood – Noncore		$~~73,586~~ 75,186			~~22,102~~ 22,146	~~95,688~~ 97,331
3	L401 Non G-XF			$~~63,065~~ 66,382			
4	L401 G-XF			~~6,520~~ 6,926			~~6,520~~ 6,926
5	Baja				$~~77,486~~ 77,427	~~17,268~~ 17,045	~~94,754~~ 94,472
6	Silverado/Mission		~~2,179~~ 2,239		~~2,937~~ 2,996	~~3,273~~ 3,297	~~8,389~~ 8,532
7	Total	$~~18,335~~ 16,270	$~~75,766~~ 77,425	$~~69,585~~ 73,308	$80,423	$52,991	$~~234,034~~ 234,035

TABLE 11B-5
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	Redwood – Core						
2	Reservation Charge	($/Dth/mo)	4.337	~~5.723~~ 5.296	~~6.304~~ 5.654	~~6.484~~ 5.770	~~6.686~~ 5.866
3	Usage Charge	($/Dth)	0.012	0.003	0.003	0.003	0.003
4	Total	($/Dth @ Full Contract)	0.155	~~0.191~~ 0.177	~~0.210~~ 0.189	~~0.216~~ 0.193	~~0.223~~ 0.196
5	Redwood Path						
6	Reservation Charge	($/Dth/mo)	8.733	~~9.008~~ 9.216	~~8.905~~ 9.322	~~8.598~~ 9.111	~~8.296~~ 8.921
7	Usage Charge	($/Dth)	0.007	~~0.002~~ 0.003	~~0.002~~ 0.003	~~0.002~~ 0.003	~~0.002~~ 0.003
8	Total	($/Dth @ Full Contract)	0.294	~~0.299~~ 0.306	~~0.295~~ 0.309	~~0.285~~ 0.302	~~0.275~~ 0.296
9	Baja Path						
10	Reservation Charge	($/Dth/mo)	9.232	~~11.002~~ 11.196	~~11.870~~ 11.952	~~13.109~~ 13.266	~~13.281~~ 13.471
11	Usage Charge	($/Dth)	0.015	0.017	0.017	0.017	0.017
12	Total	($/Dth @ Full Contract)	0.319	~~0.379~~ 0.385	~~0.407~~ 0.410	~~0.448~~ 0.453	~~0.453~~ 0.460
13	Silverado and Mission Paths						
14	Reservation Charge	($/Dth/mo)	4.483	~~5.258~~ 5.348	~~5.413~~ 5.527	~~5.630~~ 5.787	~~5.618~~ 5.805
15	Usage Charge	($/Dth)	0.006	0.004	0.004	0.004	0.004
16	Total	($/Dth @ Full Contract)	0.153	~~0.177~~ 0.180	~~0.182~~ 0.186	~~0.189~~ 0.194	~~0.189~~ 0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) Backbone transmission charges are based on ~~66.78~~67.26 percent, ~~68.11~~67.69 percent, ~~69.40~~68.62 percent, ~~70.76~~69.78 percent load factors for 2011, 2012, 2013 and 2014, respectively.

(c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

(e) Dollar differences are due to rounding.

TABLE 11B-6
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	Redwood – Core						
2	Reservation Charge	($/Dth/mo)	3.329	~~3.962~~ 3.831	~~4.269~~ 4.069	~~4.337~~ 4.144	~~4.422~~ 4.202
3	Usage Charge	($/Dth)	0.046	~~0.061~~ 0.051	~~0.070~~ 0.055	~~0.074~~ 0.057	~~0.077~~ 0.058
4	Total	($/Dth @ Full Contract)	0.155	~~0.191~~ 0.177	~~0.210~~ 0.189	~~0.216~~ 0.193	~~0.223~~ 0.196
5	Redwood Path						
6	Reservation Charge	($/Dth/mo)	5.070	~~5.567~~ 5.644	~~5.608~~ 5.788	~~5.535~~ 5.758	~~5.463~~ 5.729
7	Usage Charge	($/Dth)	0.127	~~0.116~~ 0.120	~~0.111~~ 0.119	~~0.103~~ 0.113	~~0.095~~ 0.107
8	Total	($/Dth @ Full Contract)	0.294	~~0.299~~ 0.305	~~0.295~~ 0.309	~~0.285~~ 0.302	~~0.275~~ 0.296
9	Baja Path						
10	Reservation Charge	($/Dth/mo)	7.004	~~8.252~~ 8.399	~~8.669~~ 8.729	~~9.305~~ 9.418	~~9.406~~ 9.540
11	Usage Charge	($/Dth)	0.089	~~0.107~~ 0.109	~~0.122~~ 0.123	~~0.142~~ 0.143	~~0.144~~ 0.146
12	Total	($/Dth @ Full Contract)	0.319	~~0.379~~ 0.385	~~0.407~~ 0.410	~~0.448~~ 0.453	~~0.453~~ 0.460
13	Silverado and Mission Paths						
14	Reservation Charge	($/Dth/mo)	3.084	~~3.656~~ 3.707	~~3.752~~ 3.810	~~3.888~~ 3.972	~~3.906~~ 4.004
15	Usage Charge	($/Dth)	0.052	~~0.057~~ 0.058	~~0.059~~ 0.060	~~0.061~~ 0.064	~~0.060~~ 0.063
16	Total	($/Dth @ Full Contract)	0.153	~~0.177~~ 0.180	~~0.182~~ 0.186	~~0.189~~ 0.194	~~0.189~~ 0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) Backbone transmission charges are based on ~~66.78~~67.26 percent, ~~68.11~~67.69 percent, ~~69.40~~ 68.62 percent, ~~70.76~~69.78 percent load factors for 2011, 2012, 2013 and 2014, respectively.

(c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

(e) Dollar differences are due to rounding.

TABLE 11B-7
PACIFIC GAS AND ELECTRIC COMPANY
FIRM TRANSPORTATION
EXPANSION SHIPPERS – ANNUAL RATES (G-XF)
SFV RATE DESIGN

Line No.			GA IV 2010	2011	2012	2013	2014
1	SFV Rate Design						
2	Reservation Charge	($/Dth/mo)	6.318	~~5.873~~ 6.241	~~5.680~~ 6.257	~~5.363~~ 6.036	~~5.056~~ 5.885
3	Usage Charge	($/Dth)	0.002	0.002	0.002	0.002	0.002
4	Total	($/Dth @ Full Contract)	0.210	~~0.195~~ 0.207	~~0.188~~ 0.207	~~0.178~~ 0.200	~~0.168~~ 0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(c) G-XF charges are based on the embedded cost of Line 401 and reflect a 100 percent load factor for reservation charges and a 95 percent load factor for usage charges.

(d) Dollar differences are due to rounding.

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changes in PG&E's cost structure. They are also necessary to reduce PG&E's exposure to certain cost recovery shortfalls. In addition, certain operational adjustments are necessary to accommodate the evolving northern California gas and electric generation markets.

2. Overview of Revenue Requirements and Rates

As summarized in Table 1-1, PG&E requests a GT&S revenue requirement of $529.1 million, effective January 1, 2011, for gas transmission and storage services. Over the period of 2011 through 2014, as indicated in Table 1-1, the average annual growth in the GT&S revenue requirement is approximately seven percent.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF REVENUE REQUIREMENTS
($ MILLIONS)

Line No.	Component	2010	2011	2012	2013	2014	CAGR
1	Backbone	241.0	234.0	247.5	260.4	264.6	2%
2	Local Transmission	164.0	202.8	219.5	235.1	251.8	11%
3	Storage	51.6	87.6	89.5	91.8	93.1	16%
4	Customer Access Charge	5.2	4.7	5.0	5.1	5.3	1%
5	Total	461.8	529.1	561.5	592.2	614.8	7%

Notes:

(1) The backbone revenue requirements include storage costs allocated to load balancing service and recovered through backbone rates.

(2) The backbone revenue requirements have not been reduced by the customer portion of the proposed net revenue sharing mechanism described in Section D.5 of this chapter.

(3) The 2010 local transmission revenue requirement excludes three "LT Adder" projects contemplated in Gas Accord IV, but not put into service.

(4) CAGR = Compound Annual Growth Rate

The 2011 through 2014 revenue requirements are driven by significant planned capital expenditures for backbone transmission, local transmission, and storage facilities, and significant increases in Operating and Maintenance (O&M) expenses, particularly integrity management expense.[2] In addition, in the Gas Accord IV settlement, PG&E agreed to an authorized 2010 revenue requirement that was well below its true cost of

[2] O&M and capital expenditures are discussed in detail in Chapters 5 and 6, respectively.

service[3] principally because it expected Market Storage revenues to exceed allocated Market Storage costs. In contrast, the revenue requirements proposed in this Application represent PG&E's full costs. PG&E is also proposing a separate mechanism to address potential revenue over-performance.

Table 1-2 summarizes PG&E's proposed 2011 through 2014 rates, which reflect the revenue requirements described above and the proposed policies set forth in this Application, also summarized in Section D of this chapter.

TABLE 1-2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF TRANSPORTATION AND STORAGE RATES
($/DTH, G-AFT @ FULL CONTRACT)

Line No.	Rate Category	2010	2011	2012	2013	2014	CAGR
1	Baja: Core	0.319	0.271	0.287	0.308	0.313	1%
2	Baja: Noncore	0.319	0.338	0.357	0.374	0.372	4%
3	Redwood: Core	0.155	0.271	0.287	0.308	0.313	19%
4	Redwood: Noncore	0.294	0.338	0.357	0.374	0.372	6%
5	Silverado/Mission	0.153	0.148	0.153	0.161	0.163	2%
6	G-XF	0.210	0.207	0.207	0.200	0.195	-2%
7	Local Transmission – Core ($/Dth)	0.369	0.455	0.484	0.509	0.546	10%
8	Local Transmission – Noncore ($/Dth)	0.160	0.220	0.233	0.257	0.272	14%
9	Core Firm Storage ($/Dth/mo)	0.109	0.127	0.131	0.135	0.138	6%

Notes:
(1) The backbone rates have not been reduced by the customer portion of the proposed net revenue sharing mechanism described in Section D.5 of this chapter.

The backbone rate changes are driven by the changes in revenue requirements described above; proposed rates that fully recover backbone costs at expected throughput levels; equalization of Core Redwood-Baja rates and Noncore Redwood-Baja rates; and the fact that the Gas Accord IV Core Redwood rates were particularly depressed relative to cost of service

[3] The 2010 authorized revenue requirement was $39 million below PG&E's 2010 "Litigation" revenue requirement. See "Pacific Gas and Electric Company, 2008 Gas Transmission and Storage Rate Case, Testimony Supporting the Gas Accord IV Settlement," March 15, 2007, Table 2 ("PG&E Litigation Forecast – Revenue Requirement") and Table 4 ("Settlement Revenue Requirements").

instances, the gas is also processed for removal of natural gas liquids (e.g., light hydrocarbons), water, contaminants, or inert gases. The gas is then transported to market through an intra-provincial, inter-provincial, or interstate pipeline, or a series of such pipelines. Interstate pipelines deliver out-of-state natural gas into PG&E's gas transmission system, generally at points of interconnection along the California border. Gas produced locally in California is delivered directly into PG&E's transmission system from a gas gathering pipeline system.

Once the gas reaches PG&E's system, it typically first moves through PG&E's backbone transmission system. From there, the gas moves either off-system, to customers outside of PG&E's service territory (e.g., in southern California), or on-system, into PG&E's local transmission and distribution system, where it is delivered to end-use customers. In some instances, the gas is delivered from the backbone system to underground storage for withdrawal at a future date. Upon withdrawal from storage, the gas again moves on PG&E's transmission system to either off-system or on-system destinations.

C. Gas Transmission Facilities

PG&E's gas system includes about 6,418 miles of transmission pipeline, 50 miles of gas gathering pipeline and more than 42,017 miles of distribution pipeline. The gas transmission facilities are broadly classified as either backbone transmission or local transmission. The two classifications are discussed below.

1. Backbone Transmission System

PG&E's backbone transmission system consists of the northern facilities (Lines 400, 401 and 2), the southern facilities (Lines 300 and 319), the Bay Area loop (Lines 107, 114, 131 and 303), and eight compressor stations that move gas through PG&E's system. Figure 2-1 shows PG&E's backbone and storage system.

Path, will be 2,049 MDth/d when the replacement of two compressor units at Delevan is completed in April 2011. Table 2-1 provides a breakdown of the Redwood Path capacity, Baja Path capacity and Sacramento Municipality Utility District (SMUD) Equity interests.

TABLE 2-1
PACIFIC GAS & ELECTRIC COMPANY
PG&E PIPELINE CAPACITIES

Line No.	Pipeline/Path	Firm Receipt Point Capacity (MMcf/d)	Firm Delivery Point Capacity(a) (MDth/d)
1	Line 400	1,025	1,033
2	Line 401	1,008	1,015
3	Total Redwood Path	2,033	2,049
4	Line 300 (Baja Path)	1,060	1,068
5	SMUD Equity (L401)	42.8	43.4
6	SMUD Equity (L300)	40.7	41.0

(a) Based on a shrinkage rate of 1.20 percent for on-system and 0.9 percent for off-system and an MMcf-MDth conversion factor of 1.02. SMUD Equity's MMcf-MDth and shrinkage conversions are based on their equity contract agreement.

The northern backbone system interconnects with an interstate pipeline, TransCanada's Gas Transmission Northwest (GTN) System, near Malin, Oregon. PG&E receives Canadian natural gas and small amounts of Rocky Mountain gas from GTN,[1] and transports that gas to PG&E's load centers. With the interconnection of the Ruby Pipeline in 2011, the northern backbone system will receive larger amounts of gas supply from Rocky Mountain. In addition, the northern system also delivers gas to, and receives gas from, independent storage provider facilities. Table 2-2 provides an approximate breakdown of the storage capability of existing and proposed gas storage providers.

[1] Canadian gas enters the GTN system primarily via an interconnection with TransCanada Pipeline at Kingsgate, British Columbia on the U.S.-Canadian border. Rocky Mountain gas enters the GTN system via an interconnection with Northwest Pipeline at Stanfield, Oregon.

area to PG&E's southern backbone system.[2] PG&E then delivers the gas in turn to PG&E's load centers. PG&E's southern system can also receive gas from, or deliver gas to, Southern California Gas Company (SoCalGas) at Kern River Station. Kern River Station is connected to SoCalGas' system by Line 319, a jointly-owned PG&E-SoCalGas pipeline. PG&E and SoCalGas also have other interconnections along Line 300 that are used for mutual operational assistance, but not commercial activity.

The Baja Path currently has a firm capacity of 1,040 MDth/d in the non-winter months, increasing to 1,114 MDth/d in the winter.

a. Reductions in Baja Path Capacity

PG&E began to limit the sales of Baja Path firm delivery point capacity in October 2005 from 1,148 MDth/d to 1,080 MDth/d, due to changes in the off-system market and the reduction in total horsepower at the Kettleman compressor station. In October 2007, PG&E further limited the amount of Baja Path firm capacity sales to 1,040 MDth/d in the non-winter months because PG&E could not otherwise place all of the flows at Milpitas or along Line 401/Line 2 between Panoche and Creed Station. PG&E is currently limiting firm sales to 1,040 MDth/d in the non-winter months. The conditions described above have a smaller impact during the winter months. PG&E is currently limiting firm sales to 1,114 MDth/d in the winter months. The reasons for these reductions are discussed below.

(1) Lower Off-System Flows

When Line 401 went into service, many of the original Line 401 shippers delivered gas off-system to the SoCalGas system. The shippers had firm long-term contracts and utilized the contracts nearly 100 percent of the time. The minimum off-system flows into the SoCalGas system were significant, rarely dropping below

[2] The El Paso, Transwestern, and Southern Trails pipelines connect to the San Juan Basin in northern New Mexico and the Permian Basin in west Texas. The Kern River Pipeline connects to the Rocky Mountain producing region in southern Wyoming.

(3) Placement Issues

During certain operating conditions, PG&E lacks sufficient end-use or storage injection demands along Line 300 or along Line 401/Line 2 south of Creed Station to place all of the gas that can flow on the Baja Path. Without the ability to place the gas, PG&E has to further limit the firm capacity of the Baja Path to 1,040 MDth/d in the non-winter months. During the winter months, PG&E can move 1,114 MDth/d on the Baja Path.

b. Modifications to the Baja Path Facilities

In order to address the continued reduction in the firm Baja Path capacity described above, PG&E made two changes to its facilities. First, PG&E increased the Maximum Operating Pressure (MOP) of a section of Line 300 with additional control of Pressure Limiting Station 3. The increased MOP allows for higher pressure entering the Kettleman compressor station, increasing the capacity of the Baja Path. Second, PG&E installed additional piping at the Bethany compressor station to allow the station to compress gas from south to north. Bethany was originally installed as part of the Line 401 expansion and was designed only to compress gas from north to south. By reversing the direction of compression, PG&E is able to move Baja Path supply further north, greatly reducing the placement issue during the non-winter months.

These changes allow PG&E to move 1,068 MDth/d in non-winter months and 1,145 MDth/d in winter months. However, PG&E cannot offer 1,145 year round because of air emission limits at the Hinkley compressor station. PG&E has five units at the Hinkley compressor station which have an emission permit limit of 1,500 hours of operation per 12-month period. Because of this limit, PG&E is continuing to sell firm capacity up to 1,040 MDth/d in the non-winter months, and 1,114 MDth/d in the winter months.

c. Proposed Changes in the Baja Path Facilities

PG&E held an open season for Baja Path expansion capacity from May 15 to June 8, 2009. PG&E offered two proposed expansions: one included all receipt points on the Baja Path for a maximum capacity of 30 MDth/d, and a second was limited to a new receipt point at Arvin, California, interconnecting with the Kern River/Mojave pipeline, for a maximum capacity of 200 MDth/d.

PG&E received interest in the first expansion, which included all receipt points, and awarded the full 30 MDth/d for 30 months to PG&E's Electric Gas Supply. PG&E did not receive any requests for service that would require the second expansion.

PG&E plans to increase its firm Baja Path delivery capacity to 1,068 MDth/d in the non-winter months and 1,145 MDth/d in the winter by retrofitting one additional compressor at the Hinkley compressor station with air emission reduction equipment.

2. Local Transmission

PG&E's local transmission system consists of non-backbone pipeline facilities with design operating pressures greater than 60 pounds per square inch gauge (psig).[3] The local transmission facilities include PG&E's non-backbone numbered transmission lines, distribution feeder mains, and PG&E's six-sevenths interest in the Standard Pacific Gas Line (Stanpac), which PG&E owns jointly with Chevron Pipe Line Company.[4] The various points of interconnection between PG&E's backbone transmission facilities and its local transmission and distribution facilities are collectively referred to as the "PG&E Citygate." The PG&E Citygate is an important trading point where many end-users in PG&E's territory buy gas from producers and marketers.

PG&E has slightly modified its Local Transmission planning standard by refining the determination of the Cold Winter Day (CWD) demand. The CWD demand was formerly calculated as 75 percent of the Abnormal Peak Day (APD) demand, which has a recurrence interval between 1-in-1 year and 1-in-4 years, depending on location. PG&E now has sufficient local weather data to determine the temperature for each planning area to support a 1-in-2 year recurrence interval for CWD. PG&E is now using area specific temperatures to determine CWD demand instead of using

[3] PG&E's gas transportation facilities with design operating pressures *less* than or equal to 60 psig are classified as distribution facilities.

[4] The Stanpac pipeline extends from the East Rio Vista Gas Field in a westerly direction to San Pablo Station in Contra Costa County.

E. Gas Transmission Service Proposals

1. Market Concentration Rules

PG&E proposes to continue the market concentration rules for backbone capacity adopted in CPUC Decision 02-08-070. However, for purposes of clarity, PG&E proposes to add language directly incorporating these rules into the G-AFT and G-NFT tariffs.

The current market concentration rules state that any market participant besides PG&E CGS cannot hold more than 30 percent of the capacity on either the Baja or Redwood Path on an annual basis after subtracting PG&E CGS capacities, wholesale customers, and SMUD's equity interest. For the Baja Path, the market concentration limit is currently 186 MDth/d. If PG&E CGS capacity is decreased by 100 MDth/d as proposed in Chapter 12, the market concentration limit would be 192 MDth/d. The market concentration limit for the Redwood Path is currently 413 MDth/d, but will increase to 417 MDth/d upon replacement of the Delevan units in April 2011.

If a customer reaches the market concentration limit, PG&E is prohibited from selling the customer any additional capacity on that path. PG&E is not allowed under the rules to prohibit the customer from obtaining capacity above the limit in the secondary market. The market concentration limit applies to a market participant's holdings for the next 12 months.

PG&E reports the market concentration percentage of the top five capacity holders quarterly. PG&E also reports the market concentration percentage of the top capacity holders for the next quarter.

2. Increase the Long-Term Firm Contracting Limit on the Redwood Path

PG&E anticipates that the market may want to hold additional long-term standard firm capacity on the Redwood Path to align with corresponding commitments on the Ruby Pipeline, and for that reason is proposing to increase the maximum long-term contracting limit to 800 MDth/d. Currently, PG&E is allowed to sell up to 400 MDth/d of standard firm long-term capacity on the Redwood Path for terms up to 15 years. The Redwood Path will have a firm delivery point capacity of 2,049 MDth/d. Core Procurement Groups hold 616 MDth/d and SMUD's equity interest is 43 MDth/d, leaving

1,390 MDth/d of capacity. Currently, PG&E has long-term firm capacity commitments of 245 MDth/d[6] and short-term firm capacity commitments of 49 MDth/d, leaving 1,096 MDth/d of available capacity on January 1, 2011. PG&E only has 155 MDth/d remaining of long-term firm capacity within the 400 MDth/d limit.

The construction of the Ruby pipeline to Malin will increase the competition for Redwood Path capacity. The Ruby pipeline is expected to be completed in the spring of 2011 with an initial capacity of 1,200 MDth/d. Many of the shippers on both the Ruby pipeline and the GTN pipeline have made long-term commitments for capacity and may want to extend their firm holdings to the PG&E Citygate. PG&E's proposal would allow for additional long-term capacity commitments, while still leaving 541 MDth/d of capacity available for contracts less than five years in duration.

3. Elimination of the On/Off System Option for SFV Off-System Contracts

PG&E proposes to eliminate the On/Off System option for the SFV off-system tariff. In Application 07-12-021, PG&E requested that the Commission approve a long-term contract for PG&E's Electric Fuels Department. The proposed contract had the On/Off System option from the G-AFTOFF schedule. In Decision 08-11-032, the Commission ruled that it is inappropriate to use an off-system contract when the customer intends to deliver the gas primarily on-system:[7]

> SoCalGas/SDG&E assert that PG&E seeks to improperly use Tariff Schedule G-AFTOFF for firm on-system deliveries. We agree. G-AFTOFF is plainly intended for firm off-system deliveries. The Tariff Schedule states, in relevant part, as follows: "Applicability: This rate schedule applies to the firm transportation of natural gas on PG&E's Backbone Transmission system to the **Off-System Delivery Points**." (Emphasis added.) However, the record clearly indicates that PG&E plans to use its Redwood Path capacity primarily for on-system deliveries.[8] The proper tariff for firm on-system deliveries is G-AFT

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[6] 50 MDth/d of the 245 MDth/d long-term firm capacity is subject to CPUC approval because it has a contract out provisions tied to the completion of the Ruby Pipeline. PG&E anticipates filing for CPUC approval of the contract prior to the end of 2009. PG&E expects CPUC approval based on commission approval of a similar deal with PG&E's Electric Fuels Department (D.08-11-032).

[7] D.08-11-032, p. 37-38.

[8] 4 TR 367: 20-28.

Partnership, a private non-profit economic development corporation serving San Joaquin County, supporting the conclusion that incentives were necessary to make California a cost-competitive location for PNA and retain the PNA facility in California; and (3) a review and letter of confirmation from California Business Investment Services, the state of California's office responsible for economic development, supporting the conclusion that, but for the incentive package, including discounted gas transportation rates, PNA would likely relocate its production to a location outside California.

It has been the Commission practice to accept the judgment of California Business Investment Services in determining the need for economic development incentives, like the negotiated gas transportation contract with PNA. PG&E negotiated the structure and price of the contracts over several months. PG&E and PNA exchanged several offers involving price, term and various conditions. In the negotiations, PNA expressed a strong preference for a long-term contract that would match the duration of the investment in the new furnace. In response to the customer's need for price certainty, PG&E negotiated a set of four contracts that spread the discount over 15 years and provided predictable pricing for the term of the contracts. Two of the contracts required CPUC approval, which was obtained in Decision 09-05-026.

Additional details are provided in the direct testimony in Application 08-10-013.

b. Other Negotiated NGSA Contracts

PG&E has three other continuing negotiated NGSA contracts. The customers are located in areas where they could connect directly to the Kern River/Mojave pipeline system, bypassing PG&E.

The total volume of all four contracts is approximately 10 MDth/d. The local transmission discount adjustment for these contracts is less than $0.001 per decatherm.

D. Gas Storage Service Proposals

1. Assignments of Firm Storage Rights

PG&E proposes to continue to make assignments of firm storage rights to the Monthly Balancing service, Core Firm service and Market Storage. The current firm storage service assignments, as adopted in Decision 03-12-061, p. 103, are shown in Table 3-3.

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
ASSIGNMENT OF FIRM STORAGE RIGHTS ADOPTED IN DECISION 03-12-061

Line No.	Service	Average Injection (MDth/d)	Inventory (MMDth)	Average Withdrawal (MDth/d)
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Service	157	33.5	1,111
3	Core Firm Service Counter Cyclical	50	–	50
4	Market Storage	22	4.8	159

Table 3-4 details PG&E's proposed assignments of capacity for cost allocation. The assigned firm rights are the same for Core Firm service and Monthly Balancing service as adopted in D.03-12-061. The increase firm rights for Market Storage represent the increase in firm capacities at PG&E's existing fields excluding the Gill Ranch project.

TABLE 3-4
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED ASSIGNMENT OF FIRM STORAGE RIGHTS,
EFFECTIVE APRIL 1, 2011, FOR *COST ALLOCATION*

Line No.	Service	Average Injection (MDth/d)	Inventory (MMDth)	Average Withdrawal (MDth/d)
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Service	157	33.5	1,111
3	Core Firm Service Counter Cyclical	50	–	50
4	Market Storage	194	9.0	300
5	Market Storage Counter Cyclical	194	–	300

This assignment of firm rights is used to develop the storage units in Table 3-5 which are used to allocate costs between the three services. In Application 08-07-033, PG&E stated that its cost for

TABLE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
GT&S OPERATING AND MAINTENANCE EXPENSE – 2008-2011
($000, NOMINAL)

Line No.	Description	2008 Actual	2009 Forecast	2010(a) Forecast	2011 Forecast
1	GT Total	99,406	106,024	106,498	137,038
2	GT Expense Program	90,250	94,779	94,779	119,757
3	Engineering and Maintenance	68,684	71,203	71,610	93,835
4	BX – Maintenance	49,323	50,257	50,664	64,170
5	DF – Mark and Locate/Stand-By	4,203	3,508	3,508	3,991
6	II – Integrity Management Program	15,158	17,438	17,438	25,674
7	Environmental	2,969	3,796	3,389	3,480
8	AK – Environmental Standing	2,556	3,301	2,894	3,003
9	AY – HCP Habitat Cult Protection	116	175	175	182
10	CR – Hazardous Waste Disposal	297	320	320	295
11	GSO Operations	10,903	11,560	11,560	13,914
12	CM – Operations	10,903	11,560	11,560	13,914
13	Wholesale Marketing	7,694	8,220	8,220	8,528
14	CX – Wholesale Marketing	7,694	8,220	8,220	8,528
15	Information Technology	3,704	5,611	4,357	8,230
16	Internal Remediation Expense	1,853	1,922	1,994	2,069
17	Electricity for Operations	1,921	2,017	3,667	5,267
18	Customer Access Charge	1,678	1,695	1,701	1,715

(a) PG&E is currently reviewing the 2010 GT&S O&M forecast. To the extent the approved forecast materially differs from that presented in this filing, PG&E will notify the California Public Utilities Commission (CPUC or Commission).

These expenses are shown in nominal year, SAP dollars. When using these figures in cost of service calculations, escalation has been included using escalation rates that are appropriate for each type of expense, as discussed in the next section.

The 2011 forecast represents a 29 percent increase from 2010 costs. This is increase is due primarily to cost increases in the following areas:

- Integrity Management – a highly regulated pipeline risk management program that will have increasing costs in 2011 due to a 2012 regulatory milestone and project spend associated with meeting that milestone.
- Gas Storage Compressor Maintenance – a change from a late winter maintenance schedule to an early winter maintenance schedule for PG&E-owned storage compressors.

1. Pipeline Uprate Projects

In 2008, PG&E spent less than its historical average spend on pipeline projects to increase or maintain system capacity, also known as uprate projects. Expenditures for this type of work totaled $0.415 million in 2008, which was $1.454 million lower than the $1.868 million annual average spent on this type of work from 2003 to 2007. Pipelines uprates are typically required for one of two reasons:

- Public encroachment upon the pipeline,[1] which changes the pipeline design rating, thereby requiring PG&E to either uprate/requalify the pipeline to operate at the same pressure or take a commensurate pressure reduction.
- Customer demand driving the need for greater pipeline pressure and capacity.

Consequently, spending on uprates typically increases in times of economic growth or population growth. More information concerning alternatives when a pipeline class location event occurs can be found in Chapter 6.3.a.(1). The 2008 expenditure level was unusually low because of the economic recession that hit PG&E's service area (and the rest of the country). PG&E raised the uprate expenditure level by $1.454 million to $1.868 million for 2008. This adjustment amount is shown on line 1 of Table 5-2.

2. Air Quality Management District Permit Fees

PG&E pays Air Quality Management District Permitting fees that are required in various areas of the state. The permits typically run from July 1 through June 30. As a result, the Company may pay the fee either before or after January 1 of a given year. In 2008, PG&E incurred $302,300 less in Air Quality District fees than is typically incurred by the Company because the fees were paid after January 1, 2009. Therefore, the 2008 recorded expenditures were increased by $302,300 to reflect this unusual timing and the change is reflected on line 2 of Table 5-2.

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[1] Public encroachment is the placement of buildings for public occupancy adjacent to the pipeline.

Table 6-1 summarizes PG&E's 2009 through 2014 GT&S capital spending plan by the MWCs used by PG&E to define the capital expenditures for GT&S projects:

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL CAPITAL EXPENDITURES (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline: MWC-26, -73, -75, -83, -84, -91, -98	112.1	97.4	116.1	128.0	130.4	103.7	478.2
2	Station Reliability: MWC-76, -96	98.8	103.9	52.3	52.2	47.0	58.6	210.1
3	Environmental: MWC-12	14.4	25.2	54.4	58.9	31.4	16.2	160.9
4	Base Other: MWC-5, -78	1.1	1.6	1.1	0.9	1.0	1.0	4.0
5	Total Capital Expenditures	226.4	228.1	223.9	240.0	209.8	179.5	853.2

The total capital expenditures during 2011-2014 are $853.2 million, or an average of $213.3 million per year. The forecast is primarily based on forecasts of specific projects. From 2007 through 2014, PG&E will invest over $125.0 million to install over 35 miles of new gas transmission pipeline (24-inch and greater) to meet growing customer demand in the Sacramento and Fresno areas. During this same time period, PG&E will also replace compressor engines and supporting facilities at the Topock compressor station at a cost of $120.4 million to meet new emissions requirements. These projects alone account for 36 percent of the total capital forecast.

Reliability, safety, code compliance, new business, Work Requested by Others (WRO), and additional capacity projects make up the remaining 64 percent of the forecast.

A detailed explanation of each MWC identified in the Total Capital Expenditure Forecast, and the forecast capital expenditures for that MWC, is presented in the following sections.

C. Pipeline Capital Expenditures

1. Overview (Roy A. Surges)

Table 6-2 summarizes the forecast 2009 through 2014 pipeline capital expenditures by MWC. Each MWC is discussed in detail in subsequent sections.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE CAPITAL EXPENDITURES BY MAJOR WORK CATEGORY (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline Integrity, MWC-98	19.5	23.1	23.0	22.0	15.0	11.0	71.0
2	Pipeline Safety and Reliability, MWC-75	22.9	24.4	15.3	31.1	39.8	43.0	129.2
3	Work Requested by Others, MWC-83	6.3	8.0	8.3	8.6	8.8	9.1	34.8
4	Gas Gathering, MWC-84	3.9	4.1	2.4	2.4	2.5	2.6	9.9
5	Capacity, MWC-73	54.5	33.1	28.5	59.5	58.9	34.2	181.1
6	New Business, MWC-26	3.3	3.3	36.6	3.4	3.4	3.5	46.9
7	Power Plant Gas Metering, MWC-91	1.7	1.4	2.0	1.0	2.0	0.3	5.3
8	Total Pipeline Capital Expenditures	112.1	97.4	116.1	128.0	130.4	103.7	478.2

2. Pipeline Integrity Management, MWC-98 (Roy A. Surges)

This category includes capital costs of upgrading pipelines to enable PG&E to inspect them with an In-Line-Inspection (ILI) tool, and mitigating damage found as a result of the inspection. PG&E operates its integrity management program in compliance with the requirements of the Department of Transportation, Code of Federal Regulations (CFR), 49 CFR, Part 192, Subpart O – Pipeline Integrity Management.

a. Code of Federal Regulations 49, Part 192, Subpart O

As directed by the 2002 Pipeline Safety Act, the Office of Pipeline Safety issued CFR 49, Subpart O – Pipeline Integrity Management. Subpart O requires all transmission pipeline operators, including Hinshaw pipeline operators such as PG&E, to implement a Pipeline Integrity Management Program to assess the integrity of all gas transmission pipelines located within a High Consequence Area (HCA). HCAs are defined as areas with 20 or more occupied dwellings, public gathering places or structures difficult to evacuate, e.g. nursing homes, hospitals, day cares, etc.[1]

Currently, 1,020 miles of PG&E's gas transmission pipeline systems are located within an HCA. This number is expected to grow as population density increases around PG&E's facilities. Subpart O requires all baseline integrity assessments to be completed by

[1] 49 CFR, Subpart O, Section 192.903.

TABLE 6-5
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE INTEGRITY, MWC-98 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline Integrity, MWC-98	19.5	23.1	23.0	22.0	15.0	11.0	71.0

3. Pipeline Safety and Reliability, MWC-75 (Roy A. Surges)

This category includes capital costs of improving the safety and reliability of the gas transmission pipeline system. Examples of expenditures in this category include replacing high-risk, high-consequence pipeline segments and pressure regulating facilities identified by PG&E's Pipeline Risk Management Program. This MWC also includes expenditures necessary for PG&E to comply with the many subparts in 49 CFR, Part 192, which govern the construction, maintenance and operation of natural gas transmission pipelines.

The annual capital expenditures for MWC-75 range from $15.3 million in 2011 to $43.0 million in 2014. Reliability-based investment is forecast to increase as capital spending in Pipeline Integrity Management decreases. Pipeline integrity information obtained from inspection results will be included in risk assessments and be used to prioritize pipeline safety and reliability investments. Table 6-6 summarizes the capital expenditure forecast for Pipeline Safety and Reliability, MWC-75.

TABLE 6-6
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY AND RELIABILITY, MWC-75 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Safety and Reliability	17.3	20.0	12.0	27.5	36.0	39.0	114.5
2	Cathodic Protection	3.2	3.1	2.0	2.2	2.3	2.4	8.9
3	Regulating Stations	(0.7)	0.8	1.3	1.4	1.5	1.6	5.8
4	Small Pipeline Projects < $1,000,000	3.1	0.5	–	–	–	–	–
5	Total Capital Expenditures, MWC-75	22.9	24.4	15.3	31.1	39.8	43.0	129.2

crossings), magnitude of customer outages, and magnitude of gas flow lost should the pipeline segment fail.

Utilizing these characteristics, PG&E developed a risk assessment algorithm:

$$\text{Risk} = (\text{Likelihood of Failure}) \times (\text{Consequence of Failure})$$

The algorithms and associated variables used to develop the Likelihood of Failure and Consequence of Failure were derived by analyzing root cause technical data generated from pipeline failures that occurred across the nation over a 10-year period. Even though PG&E does not have a significant pipeline failure history, insights from incidents that occurred within the PG&E system were also used to establish the risk algorithms. The algorithms are reviewed annually with subject matter experts to determine if additional data or new incidents warrant a change to the algorithms.

PG&E uses these algorithms to derive risk numbers for every unique segment of gas transmission pipe. The pipeline segment risk numbers are then used to help identify, quantify, and prioritize high-risk pipeline segments. PG&E analyzes each high-risk segment and looks for engineering solutions and risk mitigation techniques to reduce pipeline risk. Pipeline risk reduction techniques include smart pigging, pipeline replacement, pipeline relocation, pipeline rehabilitation/recoating, erosion mitigation, underwater pipeline surveys, external corrosion direct assessment, internal corrosion mitigation, landowner notification, and public education programs. The RM Program ensures that PG&E is allocating capital safety and reliability dollars and resources to the highest risk pipeline segments and regulating stations within the system.

Examples of projects within this Planning Order include:

- 2011-2014 – Replace 7.3 miles of Line 108 between Ripon and Stockton. This is the highest risk pipeline in the San Joaquin Valley. $27.8 million.

- 2010-2014 – Replace 13.9 miles of Line 107 between Livermore and Sunol. This is the highest-risk pipeline in the Bay Area. $37.7 million.
- 2011-2014 – Replace 4.3 miles of Line 131 in Fremont. This is the second highest risk pipeline in the Bay Area. $7.4 million.

b. Cathodic Protection Planning Order

This planning order includes the capital expenditures to comply with federal and state regulations for cathodic protection to protect buried steel gas pipelines from external corrosion. Capital projects primarily include replacement of deteriorated and failed pipeline coatings as well as corrosion prevention equipment such as anodes, rectifiers and monitoring systems.

c. Regulating Station Planning Order

This planning order contains capital projects to replace malfunctioning and obsolete equipment within existing gas regulation stations. A gas regulation station is designed to reduce and regulate high-pressure gas from either a backbone or local transmission pipeline to a lower pressure before it is delivered into a transmission line or distribution feeder main.

d. Pipeline Reliability < $1.0 Million Planning Order

This planning order is for pipeline reliability capital projects that cost less than $1.0 million each. Total expenditures for this planning order range from $3.1 million in 2009 to zero in 2014. Projects with costs greater than or equal to $1.0 million are assigned to their own specific planning order.

4. Work Requested by Others, MWC-83 (Roy A. Surges)

This category covers plant PG&E installs, replaces, and/or relocates at the request of third parties, typically governmental agencies for public-works projects. Cities, counties, developers, Caltrans and transportation agencies such as Valley Transit Authority and Sacramento Regional Transit drive the typical WRO relocations. Capital expenditures in this category are driven entirely by existing land rights. PG&E pays zero to 100 percent of the specific project relocation costs.

PG&E's portion of the pipeline relocation costs depends on existing land rights, easements, rights of way documents and/or franchise agreements. For example, if PG&E owns the land in fee, the outside agency is responsible for paying 100 percent of the pipeline relocation costs. If PG&E's pipeline is located within a city street under a franchise agreement, PG&E typically is obligated to fund 100 percent of the cost to relocate its facilities in response to the city's request.

Table 6-7 summarizes the capital expenditure forecast for WRO, MWC-83.

TABLE 6-7
PACIFIC GAS AND ELECTRIC COMPANY
WORK REQUESTED BY OTHERS, MWC-83 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Work Requested by Others, MWC-83	6.3	8.0	8.3	8.6	8.8	9.1	34.8

Examples of projects within this category include Caltrans highway reconstruction, installation of city sewer or storm drain lines, and new urban development. The following are examples of typical WRO projects that PG&E forecasts during this rate case period:

- 2011 – Relocate or protect in place portions of Line 114, Line 130 and Line 400 for Port of Sacramento Channel improvements. $2.6 million.
- 2011 – Relocate Line 101 for new Hillsdale Commuter Rail Station in San Mateo County. $1.4 million.
- 2012 – Relocate 1.2 miles of Line 108 for Sacramento Regional Transit Districts South Corridor light rail expansion. $2.3 million.
- 2013 – Relocate Line 118 over the San Joaquin River on State Route 99. The pipeline is currently attached to an existing bridge that is being removed and replaced. $1.0 million.

5. Gas Gathering, MWC-84 (Roy A. Surges)

This category covers capital costs associated with third party gas well connections/receipts, retirements, and divestitures of PG&E's gas gathering system.

PG&E operates about 50 miles of gas gathering pipeline and approximately 200 active California gas production receipt point meters. Other major gas gathering facilities include gas processing and dehydration stations and valve lots. Projects within this MWC include replacing and/or retiring high risk or leaking gas gathering pipelines. Anticipated projects are expected to cost less than $1.0 million each.

All new gas well production meter sets, isolation valves, service taps and extensions necessary to bring new California gas production volumes into PG&E's gas system are funded entirely by the gas producers.

Table 6-8 summarizes the capital expenditure forecast for Gas Gathering, MWC-84.

TABLE 6-8
PACIFIC GAS AND ELECTRIC COMPANY
GAS GATHERING, MWC-84 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Gas Gathering, MWC-84	3.9	4.1	2.4	2.4	2.5	2.6	9.9

6. Capacity, MWC-73 (Rick C. Brown)

This category covers capital costs of installing gas transmission facilities to increase the capacity of the gas transmission system to meet customer demand. This work includes installing new gas pipelines, installing pipelines parallel to existing gas pipelines, replacing existing pipelines with a larger diameter and/or higher pressure pipeline, increasing regulating station throughput, adding new gas regulating stations, installing a main to interconnect existing gas systems, or replacing facilities to allow the system to be uprated, which increases operating pressure and capacity.

PG&E considers a variety of operational techniques and engineering design alternatives to address every system capacity constraint before recommending and implementing the preferred solution. Transmission System Planning (TSP) engineers utilize computer flow simulation models of the PG&E gas transmission network to perform system analyses and identify the most efficient capacity projects.

PG&E engineers evaluate which of the above approaches are feasible to increase system capacity and then implement the optimum alternative.

CNG and LNG peak load shaving systems are tractor-trailer-mounted tube trailers and tankers mobilized to supplement the supply of natural gas in constrained local transmission systems during Cold Winter Day and/or Abnormal Peak Day events.

Table 6-9 summarizes the capital expenditure forecast for Capacity, MWC-73.

TABLE 6-9
PACIFIC GAS AND ELECTRIC COMPANY
CAPACITY, MWC-73 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Capacity, MWC-73	54.5	33.1	28.5	59.5	58.9	34.2	181.1

During the Gas Accord IV period (2008-2010), there has been a significant increase in local transmission capacity investments. Capacity investment increases began in 2007 and were forecast to continue through 2010 and to a lesser extent into the future. The forecast local transmission capacity investment increases were driven by significant urban expansion and rapid load growth throughout the Sacramento and San Joaquin Valleys in general and in the Sacramento, Fresno, and Merced areas in particular. Capacity projects were developed to address constraints in pipelines that move gas from high pressure backbone Line 300 and Line 400/401 located on the west side of the Central Valley, to populations on the east side of the Central Valley. These major Central Valley local transmission systems—Line 138 in the Fresno area, Line 118 in the Merced and Fresno areas, and Lines 302, 172, and 108 in the Sacramento area—were mostly installed in the 1930s through the 1960s, and have met Central Valley load growth over the past 40-50 years. Up until about 2007, smaller-scale capacity projects that eliminated relatively small, localized capacity constraints were built to maintain adequate capacity. However, the ability to utilize such smaller-scale projects to solve capacity constraints was finally exhausted. Gas Demands exceeded the capacity of the major, large-diameter Central Valley

- Line 406: Scope change to 13.9 miles of 30-inch pipeline from Line 400/401 to Line 172 to meet load growth in the greater Sacramento area. Scope change is due to work performed on detailed engineering and pipeline routing. Environmental Impact Report permitting delays has resulted in a revised forecasted operational date of November 2010. Permitting delays and increased material costs have contributed to the increased project cost. $51.8 million forecast.
- Line 407 Phase 1: Scope change to 11.7 miles of 30-inch pipeline east from the east end of Line 407 Phase 2 to the Placer Vineyard development, and 2.4 miles of 10-inch pipeline from Line 407 Phase 1 south to the Sacramento Airpark on Power Line Road to meet forecasted load growth in the greater Sacramento area. Slowed load growth and delays for the development have resulted in a revised forecasted operational date of November 2012, $51.9 million forecast.
- Line 407 Phase 2: This project was not included in the last rate case, but is part of the long-term capacity strategy for serving load growth in the Sacramento area. Line 407 Phase 2 includes 14.3 miles of 30-inch pipeline from the east end of Line 406 to the west end of Line 407 Phase 1 to meet load growth in the greater Sacramento area. This project, combined with Line 406 and Line 407 Phase 1 is the final segment of a new pipeline connecting PG&E's major backbone transmission system (Line 400/401) to the greater Sacramento area. Forecast operational date is November 2013, $51.1 million forecast.

Since the last rate case (Gas Accord IV), the California economy and housing market has slowed, which in turn reduced projected customer growth demands. Furthermore, pipeline engineering, project routing, permitting and material procurement put additional uncertainty in actual project construction and completion. Given the lower housing growth and pipeline project permitting delays described above, PG&E has rescheduled the installation of Line 406, Line 407 Phase 1, and Line 407 Phase 2.

7. New Business, MWC-26 (Rick C. Brown)

This category covers capital costs for gas transmission facilities extended from the existing gas transmission system to provide service to a new Noncore gas customer. The work includes procuring land rights and easements, facility design (i.e., estimating, mapping, engineering), material procurement, permitting, construction, and initial operation of the pipeline system. The majority of spending in this category is for service to natural gas-fired power plants. As discussed above in Section C.6, Capacity, MWC-73, PG&E considers a variety of engineering solutions and alternatives to meet every new business requirement before recommending and implementing the alternative with the best NPV. The same potential solutions for capacity projects are used for new business projects such as paralleling existing lines, increasing the operating pressure of pipelines, increasing regulator station capacity, etc.

Table 6-10 summarizes the capital expenditure forecast for New Business, MWC-26.

TABLE 6-10
PACIFIC GAS AND ELECTRIC COMPANY
NEW BUSINESS, MWC-26 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	New Business, MWC-26	3.3	3.3	36.6	3.4	3.4	3.5	46.9

New Business capital expenditures are driven by four major factors: (1) location of the generating site in relation to PG&E's existing gas transmission and distribution system; (2) projected gas demand or load; (3) duty cycle, time of year or hours during the day that the plant will operate; and (4) existing planned investments to serve Core customer load growth. Power plants located near PG&E's backbone transmission system generally have access to an abundant supply of pipeline capacity and relatively high operating pressures. On the other hand, power plants sited near the ends of PG&E's local gas transmission systems can have detrimental effects on local system capacity and pressures. In the latter instance, major local transmission reinforcement projects may be required in order to serve these new loads. PG&E applies Gas Rules 2, 15 and 16 when determining how to serve Noncore customer loads and extension allowances.

New business projects can be difficult to forecast as they are driven by individual customers with potentially large loads as opposed to general residential load growth. The above forecast assumes an annual expenditure of about $3.5 million based on historical averages. The 2011 forecast of $36.6 million is based on known, specific new business projects. Major new business projects included in this rate case that represent the majority of 2011 spending include:

- Turlock Irrigation District (TID) Almond Power Plant in south Modesto. This project includes 12.9 miles of 24-inch to 8-inch diameter pipe to meet the customer's new business demand. To reduce the overall future costs to serve Modesto area demands, PG&E forecasts increasing the pipeline diameter for some portions of the project and connect the new line to the Modesto local transmission system thereby providing longer term capacity to Modesto at lower costs than the incremental costs of other Modesto capacity alternatives. Total project cost to serve TID Almond power plant and provide capacity to Modesto during this rate case is $35.0 million. The pipeline diameter increase and the connection to the Modesto system cost about $8.0 million and are included under Capacity MWC-73. New Business, MWC-26 contains the remaining cost of the project, $27.0 million. The project is forecast to be operational in 2011.
- DG Power Stockton is a new power plant located northwest of Stockton. This project requires 4.6 miles of 12-inch diameter line to serve the plant at a cost of $4.7 million and is forecast to be operational in 2011.

8. Power Plant Gas Metering, MWC-91 (Roy A. Surges)

MWC-91 captures all capital costs for the design, material procurement, and construction of gas metering and regulation facilities to serve large Noncore gas-fired power plants. Typically, these installations range in cost from $0.5 to $0.8 million given site-specific requirements and conditions.

Table 6-11 summarizes the capital expenditure forecast for Power Plant Gas Metering, MWC-91.

TABLE 6-11
PACIFIC GAS AND ELECTRIC COMPANY
POWER PLANT GAS METERING, MWC-91 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Power Plant Gas Metering, MWC-91	1.7	1.4	2.0	1.0	2.0	0.3	5.3

D. Station Reliability Capital Expenditures (Roy A. Surges)

1. Overview

Table 6-12 summarizes the capital expenditure forecast for station reliability, consisting of MWC-76 and MWC-96. MWC-76, Station Reliability, includes capital costs of maintaining and/or improving the safety, reliability, and/or capacity of the gas compression stations and underground gas storage facilities. Examples of expenditures in this category are replacing equipment that has high outage frequency or excessive maintenance costs. MWC-96, Separately Funded Capital, includes capital costs related to the Gill Ranch Storage Field Project. These MWCs are divided into four Planning Orders: Line 300, Line 400/401, Gas Terminals, and Storage Facility Reliability.

TABLE 6-12
PACIFIC GAS AND ELECTRIC COMPANY
STATION RELIABILITY, MWC-76, -96 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	L-300 Station Reliability	13.6	13.2	10.8	9.3	7.9	9.9	37.9
2	L-400/401 Station Reliability	44.5	19.7	12.2	6.8	10.8	24.6	54.4
3	Gas Terminals	2.5	7.4	5.5	5.7	5.6	5.9	22.7
4	Storage Facility Reliability(a)	38.2	63.6	23.8	30.4	22.7	18.2	95.1
5	Total Station Reliability Capital Expenditures	98.8	103.9	52.3	52.2	47.0	58.6	210.1

(a) MWC-96, Separately Funded Capital, is reflected in the Storage Facility Reliability Planning Order.

Forecast capital expenditures for this MWC total $210.1 million for 2011-2014 and average $52.5 million per year. Major investments during the 2009–2014 timeframe include: (1) Completing the Delevan K1 and K2 replacements project that were initiated in 2009; (2) annual mandated storage gas well reworks; (3) gas compressor turbine exchange projects; and (4) Whisky Slough station upgrades to well run controls and gas processing equipment. A detailed explanation of each Planning Order within the Station Reliability MWC is provided below.

2. Line 300 Station Reliability

This Planning Order funds capital investments made at compressor, metering, and regulating stations along PG&E's Line 300. It includes costs associated with maintaining and/or improving the safety and reliability of the compressor, measurement, regulating, and auxiliary equipment located at these stations. Examples of actual and anticipated projects within this Planning Order include:

- Rebuild compressor Unit K-6 at the Topock compressor station, 2009-2010, $2.5 million.
- Replace the liners and rebuild the wastewater evaporation ponds at the Topock and Hinkley compressor stations, 2009-2013, $8.2 million.
- Exchange three gas fired turbine compressor units at the Kettleman compressor station due to each unit reaching the fired hour limit for overhaul/exchange set by Solar Gas Turbines, 2010-2012, $4.5 million.
- Rebuild the Topock compressor station compressor units and power generation units, 2009-2013. This project is necessary for reliability purposes and to comply with exhaust emission requirements that are in the process of being imposed by the Mojave Desert Air Quality Management District. See Environmental Capital Request below (MWC-12) for additional project details and cost.

3. Line 400/401 Station Reliability

This Planning Order funds capital investment made within PG&E's Line 400/401 compressor stations. It includes the same kinds of costs as the Line 300 Station Reliability Planning Order. Examples of actual and anticipated projects within this Planning Order include:

- Replace compressor units K-1 and K-2 at the Delevan compressor station, 2007-2011, $75.9 million. The existing units were installed in the late 1960s. They have exceeded their 30-year design life and have

Northwest Natural Gas Company.[2] In the first phase of development, PG&E will own an undivided interest in 25 percent of the project assets and GRS will own 75 percent. GRS is the project Operator through development and at least the first three years of commercial operations. Facility assets will include a 45,000-horsepower compressor station, a 28-mile, high-pressure pipeline to PG&E's Line 401, associated gas processing, metering and regulation, and up to 15 injection/withdrawal wells. The Gill Ranch Storage Field is projected to commence operations in third quarter 2010. The storage capacity will be allocated consistent with the ownership interest. PG&E's projected capital expenditure for the Phase 1 development of the Gill Ranch facility is $58.4 million, spread over the period 2008-2010. Phase 1 is forecasted to be operational in mid-2010.

E. Environmental Capital Expenditures (Roy A. Surges)

Table 6-13 summarizes the Environmental capital expenditure, consisting of a single MWC (MWC-12). This MWC includes project costs to install new facilities, and replace or upgrade existing gas transmission and storage facilities, in order to comply with environmental rules and regulations.

TABLE 6-13
PACIFIC GAS AND ELECTRIC COMPANY
ENVIRONMENTAL, MWC-12 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Environmental: MWC-12	14.4	25.2	54.4	58.9	31.4	16.2	160.9

Examples of actual and anticipated projects within this Planning Order include:

- Install selective catalytic reduction systems on three gas turbine compressor units at the Kettleman compressor station, 2008-2011, $16.6 million. This project is necessary to comply with a San Joaquin Air Quality Management

[2] Gill Ranch Storage, LLC, is a wholly owned subsidiary of Northwest Natural Gas Company, DBA NW Natural. NW Natural formed Gill Ranch Storage, LLC, to develop the Gill Ranch Storage project. The new subsidiary is separate from the utility and is dedicated to serving the California market.

District (AQMD) rule regarding gas turbine exhaust emissions requirements. All three units must meet the requirements by January 1, 2012.

- Retrofit unit K-1 at the Los Medanos gas storage field, 2009-2011, $6.9 million. This project is necessary to comply with a Bay Area AQMD enacted rule requiring nitric oxide emissions reduction on stationary sources. Compliance date is January 1, 2012.
- Perform greenhouse gas (GHG) emissions reduction projects at major compressor station and storage facilities, 2011-2014, $10.0 million. Based upon pending implementation of GHG emissions reduction legislation and environmental stewardship, PG&E plans to reduce GHG emissions at major stations through the use of systems to recover gas in lieu of venting flare gas to atmosphere, and install equipment that minimizes fugitive GHG emissions.

1. Topock K-Units Replacement

The Topock compressor station is the first of three compressor stations located on the Line 300 gas transmission system which transports natural gas from the Arizona/California border to the San Francisco Bay Area. Topock has nine reciprocating engine driven compressor units currently in operation.

Topock was constructed in the early 1950s and the majority of the equipment at the station is over 50 years old. PG&E anticipates needing to modify or replace the nine compressor engines by 2013 to comply with more stringent exhaust emission requirements imposed by the Mojave Desert AQMD.

The Topock Rebuild Project proposes to replace or retrofit the existing nine reciprocating compressor units. The existing units are becoming less reliable and more costly to maintain. Much of the auxiliary equipment, piping and controls associated with these units have exceeded their design life and are showing signs of their age. If modification instead of replacement were chosen to comply with air emission requirements, significant capital reliability investments will have to be made to these units over the next two to five years. Accordingly, PG&E plans to replace the units. The project cost is $95.4 million.

2. Topock P-Units Replacement

In addition to the gas compressor unit replacements, PG&E anticipates needing to modify or replace the four power generation engines at the Topock compressor station by 2013 to comply with exhaust emission requirements imposed by the Mojave Desert AQMD.

Like the K-Units, due to age, these P-Units are becoming less reliable and more costly to maintain. Based upon preliminary evaluation, PG&E plans to replace the units. The project cost is $25.0 million.

F. Other Capital Expenditures (Roy A. Surges)

1. Overview

The Base Other MWC is a combination of two MWCs. They have been combined into one category because their combined total is relatively small, as shown in Table 6-14. A description of each of these MWCs is provided below.

TABLE 6-14
PACIFIC GAS AND ELECTRIC COMPANY
BASE OTHER, MWC-05, -78 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Tools and Equipment, MWC-05	0.5	0.3	0.3	0.3	0.3	0.3	1.2
2	Manage Buildings, MWC-78	0.6	1.3	0.8	0.6	0.7	0.7	2.8
3	Total Base Other Capital Expenditures	1.1	1.6	1.1	0.9	1.0	1.0	4.0

2. Tools and Equipment, MWC-05

This MWC is used to fund the purchase of new equipment and tools for use by PG&E employees on the GT&S system.

3. Manage Buildings, MWC-78

This MWC is used to fund capital replacements and improvements to PG&E buildings and structures throughout the GT&S system. An example of such a project would be the installation of a bathroom, offices, meeting room, and storage space at a PG&E Maintenance Headquarters.

TABLE 8-1
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST

Line No.	Revenue Requirement	($000s) 2011	2012	2013	2014
1	Base Revenue Requirement	529,928	561,292	591,892	613,904
2	*Less:* Other Operating Revenues	(2,698)	(2,698)	(2,698)	(2,698)
3	*Plus:* Carrying Costs on Working Gas and Load Balancing Gas	1,852	2,866	3,042	3,583
4	Total	529,082	561,460	592,236	614,789

Note:
The calculation of Carrying Costs on Working Gas and Load Balancing Gas can be found PG&E's Chapter 11, "Cost Allocation and Rate Design," workpapers.

The 2011 base revenue requirement of $529.9 million (Line 1 of Table 8-1) is presented in Table 8-2 below, broken down by Unbundled Cost Categories (UCC).

TABLE 8-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 BASE REVENUE REQUIREMENT

Line No.	Unbundled Cost Categories	($000s)
1	GT – Gathering (501)	13,146
2	GS – Storage Services – McDonald Island (511)	65,134
3	GS – Storage Services – Los Medanos/Pleasant Creek (512)	21,454
4	GS – Storage Services – Gill Ranch (513)	11,295
5	GT – Local Transmission (520)	202,950
6	GT – Transmission: Northern Path – Line 401 (521)	74,000
7	GT – Transmission: Northern Path – Line 400 (522)	23,056
8	GT – Transmission: Northern Path – Line 2 (523)	4,257
9	GT – Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	11,154
10	GT – Transmission: Southern Path – Line 300 South Topock to Panoche (525)	82,263
11	GT – Transmission: Bay Area Loop (526)	16,522
12	GT – Customer Access Charge (CAC) (540)	4,697
13	Total Year 2011	529,928

Table 8-3 shows the requested base revenue requirements, broken down by UCC, for the post-test years 2012, 2013 and 2014.

TABLE 8-3
PACIFIC GAS AND ELECTRIC COMPANY
2012-2014 BASE REVENUE REQUIREMENT

Line No.	Unbundled Cost Categories	($000s) 2012	2013	2014
1	GT – Gathering (501)	13,383	13,865	14,377
2	GS – Storage Services – McDonald Island (511)	65,973	67,750	68,747
3	GS – Storage Services – Los Medanos/Pleasant Creek (512)	22,150	22,905	23,173
4	GS – Storage Services – Gill Ranch (513)	10,951	10,801	10,628
5	GT – Local Transmission (520)	219,660	235,244	251,995
6	GT – Transmission: Northern Path – Line 401 (521)	74,186	71,619	69,864
7	GT – Transmission: Northern Path – Line 400 (522)	25,660	26,631	27,804
8	GT – Transmission: Northern Path – Line 2 (523)	4,749	4,614	4,589
9	GT – Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	11,166	10,859	10,559
10	GT – Transmission: Southern Path – Line 300 South Topock to Panoche (525)	91,314	103,450	106,713
11	GT – Transmission: Bay Area Loop (526)	17,142	19,026	20,141
12	GT – Customer Access Charge (CAC) (540)	4,956	5,127	5,314
13	Total	561,292	591,892	613,904

B. Cost Structure

GT&S rates currently in effect are based on the all party Gas Accord IV Settlement approved in Decision 07-09-045. PG&E generally has maintained the same cost structure in this Application, with changes described below.

In PG&E's Gas Accord I, Decision 97-08-055, the Commission approved restructuring of the gas transportation and commodity sales markets in PG&E's service territory. As a result of this restructuring, customers gained the option of obtaining parts of utility services from different suppliers. This decision required PG&E to unbundle its utility services. In order to assist the Commission in determining the cost of its unbundled services, PG&E began to separate its gas Results of Operations in its various rate setting proceedings into UCCs. A UCC corresponds to a particular asset or group of assets. In Gas Accord IV, PG&E used eight UCCs for rate design purposes. In this proceeding, PG&E presents 12 UCCs in order to provide a greater level of cost granularity. However, for rate design purposes, PG&E collapses these 12 UCCs into the same eight UCCs used in Gas Accord IV, plus one new UCC for the Gill Ranch storage project.[1] Table 8-4 shows a mapping between the eight UCCs used in Gas Accord IV, and the 12 UCCs used in this proceeding.

[1] See Chapter 11, "Cost Allocation and Rate Design."

TABLE 8-5
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,146	65,134	21,454	11,295	202,784	73,308	23,056	4,257	11,154	80,423	16,522	4,697	527,230
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,146	65,134	21,454	11,295	202,950	74,000	23,056	4,257	11,154	82,263	16,522	4,697	529,928
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	3,908	0	0	0	0	0	0	0	0	0	0	0	3,908
6	Storage	0	12,411	3,859	2,237	0	0	0	0	0	0	0	0	18,506
7	Transmission	0	0	0	0	42,640	4,855	6,905	415	764	24,303	5,550	0	85,432
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	313	313
9	Customer Accounts	82	147	87	0	652	20	109	0	36	383	60	1,041	2,617
10	Uncollectibles	37	181	60	31	565	206	64	12	31	229	46	13	1,476
11	Customer Services	359	2,096	1,241	0	3,126	90	476	0	159	1,678	262	0	9,488
12	Administrative and General	2,471	4,436	2,627	88	19,816	614	3,151	140	1,077	11,627	1,883	634	48,564
13	Franchise Requirements	125	621	204	108	1,934	705	220	41	106	784	157	45	5,050
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Subtotal Expenses:	6,982	19,891	8,078	2,464	68,734	6,490	10,925	608	2,173	39,004	7,959	2,047	175,355
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	415	2,713	783	348	8,456	5,318	808	304	635	3,107	517	102	23,508
21	Payroll	279	529	314	12	2,226	158	342	23	67	1,277	275	86	5,589
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	130	1,664	464	144	3,420	2,812	172	93	266	726	272	94	10,257
25	Federal Income	976	8,297	2,304	1,795	22,948	9,719	1,548	158	1,199	5,336	1,430	251	55,963
26	Total Taxes	1,814	13,227	3,880	2,300	37,157	18,011	2,888	579	2,173	10,508	2,504	536	95,578
27	Depreciation	2,141	11,342	3,672	1,431	35,067	21,608	4,969	1,161	2,817	16,841	2,511	1,341	104,901
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	10,937	44,460	15,630	6,195	140,958	46,109	18,782	2,348	7,163	66,353	12,974	3,924	375,834
31	Net for Return	2,209	20,673	5,825	5,100	61,992	27,891	4,274	1,909	3,991	15,910	3,548	773	154,094
32	Rate Base	25,128	235,190	66,263	58,021	705,252	317,307	48,628	21,716	45,402	180,998	40,365	8,791	1,753,060
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

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TABLE 8-6
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 RATE BASE
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	WEIGHTED AVERAGE PLANT:													
1	Plant Beginning of Year	68,287	418,384	123,937	59,136	1,355,235	767,064	142,132	51,934	106,235	508,725	84,157	22,319	3,707,544
2	Net Additions	884	890	1,564	10	21,134	20,541	21,496	15	118	3,863	206	1,107	71,829
3	Total Weighted Average Plant	69,171	419,274	125,501	59,146	1,376,369	787,604	163,628	51,949	106,353	512,588	84,364	23,425	3,779,373
	WORKING CAPITAL:													
4	Material and Supplies - Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Material and Supplies - Other	0	316	87	0	6,228	57	0	0	0	0	0	0	6,688
6	Working Cash	127	(283)	(50)	219	1,566	(2,134)	515	105	114	1,593	21	66	1,859
7	Total Working Capital	127	33	37	219	7,794	(2,077)	515	105	114	1,593	21	66	8,546
	ADJUSTMENTS FOR TAX REFORM ACT:													
8	Deferred Capitalized Interest	16	(145)	(41)	(0)	376	4,590	45	14	36	134	24	(1)	5,047
9	Deferred Vacation	46	301	84	0	885	22	104	35	77	346	58	32	1,990
10	Deferred CIAC Tax Effects	0	0	0	0	0	0	0	0	0	0	0	425	425
11	Total Adjustments	62	156	43	0	1,260	4,612	149	49	112	480	81	457	7,462
12	CUSTOMER ADVANCES	0	0	0	0	0	0	0	0	0	0	0	0	0
	DEFERRED TAXES													
13	Accumulated Regulatory Assets	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Accumulated Fixed Assets	6,455	31,654	8,739	1,992	132,603	130,669	14,022	4,937	10,671	47,668	8,188	820	398,418
15	Accumulated Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Deferred ITC	179	931	263	1	3,426	2	404	136	297	1,340	223	62	7,263
17	Deferred Tax - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Deferred Taxes	6,634	32,585	9,002	1,993	136,028	130,670	14,426	5,073	10,968	49,008	8,412	882	405,681
19	DEPRECIATION RESERVE	37,598	151,687	50,316	(649)	544,143	342,161	101,239	25,314	50,210	284,656	35,689	14,275	1,636,[illegible]40
20	TOTAL RATE BASE	25,128	235,190	66,263	58,021	705,252	317,307	48,628	21,716	45,402	180,998	40,365	8,791	1,753,[illegible]60

ERRATA 04/23/10

TABLE 8-7
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 INCOME TAXES AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
1	Revenues	13,146	65,134	21,454	11,295	202,950	74,000	23,056	4,257	11,154	82,263	16,522	4,697	529,928
2	O&M Expenses	6,982	19,891	8,078	2,464	68,734	6,490	10,925	608	2,173	39,004	7,959	2,047	175,355
3	Nuclear Decommissioning Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Taxes Other Than Income	708	3,266	1,112	361	10,789	5,479	1,168	328	708	4,446	802	191	29,358
6	Subtotal	5,456	41,976	12,265	8,470	123,427	62,031	10,963	3,321	8,273	38,813	7,761	2,459	325,215
	DEDUCTIONS FROM TAXABLE INCOME:													
7	Interest Charges	699	6,538	1,842	1,613	19,606	8,821	1,352	604	1,262	5,032	1,122	244	48,735
8	Fiscal/Calendar Adjustment	16	81	45	346	467	(45)	8	(4)	(3)	127	4	3	1,045
9	Operating Expense Adjustments	(107)	(210)	(114)	(4)	(808)	22	(92)	(10)	(55)	(501)	(86)	(27)	(1,993)
10	Capitalized Interest Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capitalized Inventory Adjustment	44	1	1	0	904	1	105	38	80	336	57	0	1,566
12	Vacation Accrual Reduction	(4)	(25)	(7)	(0)	(73)	(2)	(9)	(3)	(6)	(28)	(5)	(3)	(164)
13	Capitalized Other	12	22	13	0	100	0	16	1	5	59	9	3	242
14	Subtotal Deductions	660	6,408	1,780	1,956	20,196	8,797	1,380	625	1,284	5,024	1,162	221	49,432
	CCFT TAXES:													
15	State Operating Expense Adjustment	20	271	71	(0)	431	250	48	21	38	154	26	2	1,332
16	State Tax Depreciation - Declining Balan	0	0	0	0	0	0	0	0	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	3,019	15,813	4,882	4,872	60,045	16,566	7,165	1,651	3,922	22,777	3,388	1,053	145,154
18	State Tax Depreciation - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Removal Costs	119	505	99	3	3,318	136	250	1	10	1,924	58	64	6,485
20	Repair Allowance	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Subtotal Deductions	3,817	22,997	6,832	6,831	83,989	25,750	8,842	2,298	5,254	29,879	4,575	1,339	202,402
22	Taxable Income for CCFT	1,638	18,979	5,433	1,639	39,438	36,281	2,121	1,023	3,019	8,934	3,187	1,120	122,812
23	CCFT	145	1,678	480	145	3,486	3,207	188	90	267	790	282	99	10,857
24	State Tax Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Current CCFT	145	1,678	480	145	3,486	3,207	188	90	267	790	282	99	10,857
26	Deferred Taxes - Reg Asset	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Deferred Taxes - Interest	2	24	6	(0)	38	22	4	2	3	14	2	0	118
28	Deferred Taxes - Vacation	(0)	(2)	(1)	(0)	(6)	(0)	(1)	(0)	(1)	(3)	(0)	(0)	(14)
29	Deferred Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	(16)	(36)	(22)	(1)	(98)	(417)	(19)	1	(4)	(75)	(11)	(5)	(702)
31	Total CCFT	130	1,664	464	144	3,420	2,812	172	93	266	726	272	94	10,257

ERRATA 04/23/10

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TABLE 8-7
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2011 INCOME TAXES AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	FEDERAL TAXES:													
32	CCFT - Prior Year	(179)	207	115	22	3,151	4,011	135	1,124	723	1,514	25	165	11,013
33	Federal Operating Expense Adjustment	38	516	135	(0)	832	(330)	91	40	73	296	51	4	1,748
34	Fed. Tax Depreciation - Declining Balanc	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	2,789	13,851	4,340	5,331	55,876	5,528	6,801	1,455	3,490	21,056	3,050	1,033	124,599
37	Federal Tax Depreciation - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Removal Costs	119	505	99	3	3,318	136	250	1	10	1,924	58	64	6,485
39	Repair Allowance	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Preferred Dividend Credit	3	3	1	0	68	0	8	3	6	26	4	0	123
41	Subtotal Deductions	3,430	21,491	6,470	7,311	83,440	18,142	8,665	3,248	5,586	29,840	4,290	1,487	193,400
42	Taxable Income for FIT	2,026	20,485	5,795	1,159	39,987	43,889	2,298	73	2,687	8,973	3,471	972	131,815
43	Federal Income Tax	709	7,170	2,028	406	13,995	15,361	804	26	940	3,141	1,215	340	46,135
44	Deferred Taxes - Reg Asset	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0
46	Deferred Taxes - Interest	6	77	20	(0)	127	(211)	14	6	11	45	8	1	105
47	Deferred Taxes - Vacation	(1)	(8)	(2)	(0)	(23)	(1)	(3)	(1)	(2)	(9)	(2)	(1)	(52)
48	Deferred Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	263	1,058	258	1,389	8,849	(5,430)	733	127	249	2,160	209	(89)	9,775
50	Total Federal Income Tax	976	8,297	2,304	1,795	22,948	9,719	1,548	158	1,199	5,336	1,430	251	55,963

ERRATA 04/23/10

TABLE 8-8
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2012 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,383	65,973	22,150	10,951	219,494	73,494	25,660	4,749	11,166	89,474	17,142	4,956	558,594
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,383	65,973	22,150	10,951	219,660	74,186	25,660	4,749	11,166	91,314	17,142	4,956	561,292
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,024	0	0	0	0	0	0	0	0	0	0	0	4,024
6	Storage	0	12,680	3,966	2,273	0	0	0	0	0	0	0	0	18,920
7	Transmission	0	0	0	0	43,708	4,965	7,073	425	783	24,912	5,693	0	87,559
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	322	322
9	Customer Accounts	85	152	90	0	676	21	113	0	38	397	62	1,075	2,708
10	Uncollectibles	37	184	62	31	612	207	71	13	31	254	48	14	1,563
11	Customer Services	371	2,171	1,286	0	3,234	93	493	0	164	1,735	271	0	9,818
12	Administrative and General	2,212	3,970	2,351	79	17,736	549	2,820	126	964	10,407	1,685	568	43,468
13	Franchise Requirements	128	629	211	104	2,093	707	245	45	106	870	163	47	5,349
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	429	769	456	15	3,437	106	547	24	187	2,017	327	110	8,424
18	Subtotal Expenses:	7,285	20,556	8,421	2,502	71,497	6,648	11,361	634	2,273	40,592	8,250	2,136	182,154
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	426	2,807	820	349	8,956	5,323	817	305	636	3,672	600	108	24,818
21	Payroll	290	549	326	13	2,310	164	355	24	69	1,324	285	89	5,798
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	115	1,607	465	116	4,136	2,829	328	137	265	918	240	104	11,258
25	Federal Income	813	7,625	2,204	1,639	26,023	10,071	2,152	696	1,353	6,758	1,273	318	60,922
26	Total Taxes	1,657	12,611	3,828	2,116	41,531	18,389	3,669	1,162	2,329	12,734	2,408	622	103,057
27	Depreciation	2,196	11,729	3,835	1,433	37,730	21,898	5,294	1,162	2,823	18,314	2,664	1,378	110,456
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,138	44,895	16,084	6,051	150,758	46,936	20,324	2,957	7,425	71,641	13,322	4,135	395,667
31	Net for Return	2,246	21,078	6,066	4,900	68,903	27,250	5,337	1,792	3,741	19,673	3,820	821	165,625
32	Rate Base	25,547	239,794	69,012	55,741	783,876	310,014	60,712	20,385	42,559	223,811	43,454	9,338	1,884,243
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

ERRATA 04/23/10

TABLE 8-9
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2013 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	13,865	67,750	22,905	10,801	235,078	70,927	26,631	4,614	10,859	101,610	19,026	5,127	589,194
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	13,865	67,750	22,905	10,801	235,244	71,619	26,631	4,614	10,859	103,450	19,026	5,127	591,892
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,145	0	0	0	0	0	0	0	0	0	0	0	4,145
6	Storage	0	12,961	4,077	2,311	0	0	0	0	0	0	0	0	19,349
7	Transmission	0	0	0	0	44,859	5,084	7,255	436	803	25,568	5,847	0	89,852
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	330	330
9	Customer Accounts	88	157	93	0	701	22	117	0	39	411	64	1,112	2,804
10	Uncollectibles	39	189	64	30	655	199	74	13	30	288	53	14	1,649
11	Customer Services	384	2,250	1,332	0	3,346	96	510	0	170	1,795	281	0	10,164
12	Administrative and General	2,298	4,124	2,442	82	18,424	571	2,929	130	1,001	10,811	1,751	590	45,154
13	Franchise Requirements	132	646	218	103	2,242	683	254	44	103	986	181	49	5,641
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	522	936	555	19	4,183	130	665	30	227	2,454	397	134	10,252
18	Subtotal Expenses:	7,607	21,263	8,781	2,545	74,410	6,785	11,804	653	2,375	42,313	8,574	2,229	189,338
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	445	2,885	838	349	9,657	5,362	845	312	639	3,831	635	119	25,916
21	Payroll	301	570	338	13	2,396	170	369	25	72	1,374	296	92	6,016
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	115	1,641	483	102	4,620	2,614	345	121	234	1,596	335	103	12,310
25	Federal Income	832	7,837	2,291	1,596	28,195	9,244	2,167	621	1,235	9,490	1,686	317	65,533
26	Total Taxes	1,706	12,957	3,965	2,061	44,974	17,394	3,763	1,080	2,186	16,354	2,962	634	110,036
27	Depreciation	2,258	12,132	3,971	1,435	40,381	21,981	5,367	1,175	2,831	20,207	2,963	1,413	116,114
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,571	46,351	16,717	6,041	159,766	46,160	20,933	2,908	7,391	78,875	14,499	4,275	415,488
31	Net for Return	2,294	21,399	6,188	4,760	75,477	25,459	5,698	1,705	3,468	24,575	4,527	852	176,404
32	Rate Base	26,096	243,451	70,399	54,157	858,674	289,639	64,825	19,399	39,456	279,577	51,507	9,693	2,006,872
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

TABLE 8-10
PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE
2014 RESULTS OF OPERATIONS AT PROPOSED RATES (UCCS)
(THOUSANDS OF DOLLARS)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2011
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	REVENUE:													
1	Revenue Collected in Rates	14,377	68,747	23,173	10,628	251,829	69,172	27,804	4,589	10,559	104,873	20,141	5,314	611,206
2	Plus Other Operating Revenue	0	0	0	0	166	692	0	0	0	1,840	0	0	2,698
3	Total Operating Revenue	14,377	68,747	23,173	10,628	251,995	69,864	27,804	4,589	10,559	106,713	20,141	5,314	613,904
	OPERATING EXPENSES:													
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gathering	4,270	0	0	0	0	0	0	0	0	0	0	0	4,270
6	Storage	0	13,257	4,194	2,352	0	0	0	0	0	0	0	0	19,802
7	Transmission	0	0	0	0	46,000	5,201	7,434	447	824	26,218	5,999	0	92,123
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	339	339
9	Customer Accounts	91	163	96	0	726	23	121	0	40	426	67	1,149	2,903
10	Uncollectibles	40	191	65	30	702	195	77	13	29	297	56	15	1,710
11	Customer Services	397	2,331	1,380	0	3,463	99	527	0	176	1,858	290	0	10,522
12	Administrative and General	2,388	4,287	2,539	85	19,150	593	3,045	136	1,041	11,237	1,820	613	46,932
13	Franchise Requirements	137	655	221	101	2,402	666	265	44	101	1,017	192	51	5,851
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Other Adjustments	522	936	555	19	4,183	130	665	30	227	2,454	397	134	10,252
18	Subtotal Expenses:	7,845	21,820	9,049	2,586	76,625	6,907	12,135	669	2,438	43,507	8,822	2,301	194,703
	TAXES:													
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property	461	2,933	852	349	10,113	5,394	852	312	641	3,951	704	121	26,682
21	Payroll	312	591	351	14	2,486	176	382	25	75	1,426	307	96	6,241
22	Business	2	4	3	0	20	1	3	0	1	12	2	1	49
23	Other	11	19	11	0	86	3	14	1	5	51	8	3	212
24	State Corporation Franchise	126	1,647	475	87	5,409	2,468	401	119	208	1,670	354	110	13,075
25	Federal Income	884	7,884	2,262	1,542	31,479	8,764	2,408	619	1,143	9,634	1,778	348	68,745
26	Total Taxes	1,795	13,079	3,954	1,992	49,593	16,807	4,061	1,077	2,072	16,743	3,153	679	115,004
27	Depreciation	2,339	12,438	4,048	1,436	43,178	22,149	5,460	1,198	2,842	20,871	3,182	1,449	120,588
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Total Operating Expenses	11,979	47,338	17,051	6,014	169,396	45,862	21,655	2,943	7,352	81,120	15,157	4,428	430,295
31	Net for Return	2,398	21,410	6,122	4,614	82,599	24,002	6,148	1,646	3,206	25,593	4,984	886	183,609
32	Rate Base	27,286	243,570	69,648	52,489	939,692	273,059	69,944	18,726	36,478	291,163	56,705	10,074	2,088,836
	RATE OF RETURN:													
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**	**8.79%**
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**	**11.35%**

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TABLE 10-1
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST COMPARISON
(MDTH/DAY)

Line No.		2008	2011	2012	2013	2014
1	Core					
2	Residential	548	554	557	556	552
3	Commercial	234	233	239	243	243
4	Small Commercial	213	212	218	221	221
5	Large Commercial	20	21	21	22	22
6	Interdepartmental	0	0	0	0	0
7	Core Natural Gas Vehicles	5	6	6	6	6
8	Total Core	787	793	802	805	802
9	Noncore					
10	Industrial	484	464	465	468	469
11	Industrial Distribution	69	69	69	71	72
12	Industrial Transmission	415	395	396	397	396
13	Noncore Natural Gas Vehicles	1	1	1	2	2
14	Cogeneration	200	201	201	201	201
15	Power Plants and Miscellaneous Electric Generation	598	509	532	522	543
16	Total Noncore	1,283	1,175	1,199	1,192	1,214
17	Wholesale	10	10	10	10	10
18	Total Volumes	2,080	1,978	2,011	2,007	2,026

B. Core and Noncore Gas Demand Forecast (Other Than Electric Generation) (Kate M. Tiedeman)

1. Forecasting Methodology

PG&E forecasts gas demand by various means. Some categories of gas demand are forecasted using econometric models, which rely on statistical analysis of historical data to derive relationships between economic and demographic data and gas demand. Other categories of gas demand are forecasted using external forecasts, which rely on information from customers, account service representatives and other sources.

Econometric models are used to develop demand forecasts for residential, small commercial, large commercial and Noncore industrial customer classes. The relationships between gas demand and factors such as economic and demographic activity, prices, weather, and seasonal-use patterns are developed based on historical data. The final specification of a

Application 08-07-031 are 2,500 thousand decatherms (MDth), 2,000 MDth, 3,200 MDth and 3,100 MDth for years 2011, 2012, 2013 and 2014, respectively. PG&E has built these reductions into the forecast used in developing PG&E gas demand for this GT&S rate case period.

3. Core Demand Forecast

Core demand is projected to average approximately 800 MDth/d during 2011-2014. The Core forecast demands are shown in Table 10-1. A discussion of the major customer groups composing the Core class follows.

a. Residential Demand

For the GT&S rate case period 2011-2014, PG&E projects residential usage to average approximately 555 MDth/d. This is about 1.2 percent above the recorded 2008 amount. Month-to-month, residential gas demand is primarily driven by temperature, with smaller economic and price effects. It is the longer-term impacts of EE programs and building standards that have driven residential usage lower both on a per household basis and total basis.

b. Commercial Demand

The projected annual average usage for commercial gas demand[2] during the GT&S rate case period is approximately 239 MDth/d, 2.1 percent above the 2008 level.

4. Noncore Demand Forecast

Proposed Noncore non-EG demand is projected to be about 468 MDth/d during the GT&S rate case period. The forecast of Noncore demand is shown in Table 10-1. A discussion of the major non-EG customer classes composing Noncore follows.

a. Industrial Distribution Demand

The projected demand for the industrial distribution[3] class of customers averages about 70 MDth/d over the 2011-2014

[2] To qualify for this rate schedule, a core customer's average monthly gas use must not have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

GT&S rate case period. This is about 2.0 percent higher than the recorded 2008 amount of 69 MDth/d.

b. Industrial Transmission Demand

The projected demand for the industrial transmission customer class[4] is 393 MDth/d for the 2011-2014 GT&S rate case period, about 4.5 percent below 2008 recorded.

c. Industrial Backbone Demand

There are currently three Noncore industrial customers that receive backbone level service. Their combined average usage for the 2011-2014 period is projected at 3.2 MDth/d, about 3.0 percent below the recorded 2008 amount of 3.3 MDth/d. Backbone-level end use service began in 2005.

5. Wholesale Demand Forecast

PG&E currently serves six wholesale customers: the city of Palo Alto, the city of Coalinga, West Coast Gas (Castle and Mather Field locations), Island Energy, and Alpine Natural Gas. The first two customers account for over 90 percent of total wholesale demand, and the first customer accounts for over 85 percent of total wholesale demand. The forecasts for these customers' loads are based on customer-specific information collected from the customers.

The proposed annual average gas demand for these six customers is projected to be 10 MDth/d for the GT&S rate case period—virtually constant compared to the 2008 recorded amount.

6. Summary of On-System Cold Year Demand Forecast

Table 10-2 shows the total on-system demand forecast for cold temperature conditions. This forecast is developed for a 1-in-35 cold year

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[3] To qualify for the industrial distribution rate schedule, a customer's average monthly gas use must have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

[4] To qualify for the industrial transmission rate schedule, a customer must be of noncore status, which means that it must have maintained an average monthly usage in excess of 20,800 therms during the previous year, excluding those months in which usage was 200 therms or less. To the extent that its average monthly usage exceeds 250,000 therms, it is connected to facilities that are on transmission pressure (greater than 60 psi).

scenario. The cold year peak month (January) demands are used to allocate local transmission costs between Core and Noncore customer classes.

TABLE 10-2
PACIFIC GAS AND ELECTRIC COMPANY
COLD YEAR GAS DEMAND FORECAST
(MDTH/DAY)

Line No.		2008	2011	2012	2013	2014
1	Core					
2	Residential	548	615	619	620	620
3	Commercial	234	250	256	261	262
4	Small Commercial	213	228	234	238	239
5	Large Commercial	20	22	22	23	23
6	Interdepartmental	0	0	0	0	0
7	Core Natural Gas Vehicles	5	6	6	6	6
8	Total Core	787	871	881	887	888
9	Noncore					
10	Industrial	484	466	469	472	471
11	Industrial Distribution	69	72	73	75	75
12	Industrial Transmission	415	395	396	397	396
13	Noncore Natural Gas Vehicles	1	1	1	2	2
14	Cogeneration	200	201	201	201	201
15	Power Plants and Miscellaneous Electric Generation	598	515	538	529	551
16	Total Noncore	1,283	1,183	1,209	1,204	1,225
17	Wholesale	10	13	11	11	11
18	Total Volumes	2,080	2,067	2,101	2,102	2,124

C. Electric Generation Gas Demand Forecast (Eric Hsu)

This section presents forecasts of natural gas deliveries by PG&E to electric generators. For forecasting, PG&E divides electric generators into three groups, defined as follows:

- Cogeneration. This group consists of gas-fired cogenerators whose output is generally not sensitive to prices in the electricity and gas markets because they generate electricity along with some other energy product, usually steam. Many of these plants have Qualifying Facility contracts that require PG&E to purchase their power but do not allow PG&E to dispatch them. This group includes all but three of the 235 cogenerators that have had gas delivered by PG&E since the beginning of 2008.

- Power plants. This group consists of gas-fired electric generators whose output varies in response to prices in the wholesale electricity and gas markets. The power plant group includes combined cycle power plants, gas turbine (GT or “peaker”) plants, and old steam-boiler plants. The power plant group also includes the cogeneration plants that were not included in the cogeneration group (defined above) because some or all of their generation is dispatchable. Finally, the power plant group includes gas deliveries to the Sacramento Municipal Utility District (SMUD) power plants in excess of SMUD’s 88 MDth/d equity share of pipeline capacity (including both firm and as-available). Gas deliveries to SMUD in excess of its equity share are subject to PG&E rates and are therefore included in PG&E’s forecasts for rate-setting purposes.
- Miscellaneous. This group consists of the remaining 17 electric generators that are neither in the cogeneration nor power plants groups (defined above). Each of these generators consumes 2.5 MDth/d or less. Of the 17 generators in this group, 13 use solar energy or biomass as their primary fuel but use gas as a secondary fuel.

1. Forecast of Cogeneration and Miscellaneous Electric Generation Gas Demand

PG&E’s forecasts of cogeneration and miscellaneous electric generation gas demand are 201 and 8 MDth/d, respectively, based on the most recent 12 months of actual deliveries (June 2008 through May 2009). This approach was used in previous GT&S rate cases and BCAPs. The cogeneration forecast is marginally more than the calendar 2008 demand of 200 MDth/d. The miscellaneous electric generation forecast is slightly more than the calendar 2008 demand of 6 MDth/day.

The 20 largest accounts consume over 83 percent of the total; most of the remaining accounts consume less than 0.1 MDth/d. PG&E’s database of large electrical and gas interconnection projects currently includes no cogeneration or combined heat-and-power projects under development that would take PG&E gas service. New and proposed plants are brought to PG&E’s attention for provision of gas service; in contrast, no advance notice is needed for shutdowns. To the best of PG&E’s knowledge, none of

PG&E's large cogeneration customers plans to expand or shut down during the rate-case period.

Smaller cogeneration and miscellaneous generators have been starting and ending their gas service at about the same rate. Between June 2006 and May 2009, PG&E has begun serving 16 new cogeneration and miscellaneous generators that collectively use about 0.6 MDth/d, while service ended to four facilities that collectively used about 2.1 MDth/d.

In view of recent history, PG&E believes the most reasonable forecasts of cogeneration and miscellaneous electric generation gas demands for the rate case period are the most recent 12 months of actual gas demands. If higher forecasts are adopted, the forecast of gas demand for power plants should be reduced. Higher gas demand by cogeneration and miscellaneous generators implies greater output of electricity, which would reduce the demand for electricity from power plants.

2. Forecast of Power Plant Gas Demand

PG&E's forecast of gas deliveries to power plants is 501 MDth/d in 2011, 524 MDth/d in 2012, 514 MDth/d in 2013, and 535 MDth/d in 2014. These amounts have been reduced by PG&E's forecast of gas delivered to power plants by other pipelines. The numbers in Table 10-1 include the forecast of miscellaneous electric generation gas demand of 8 MDth/d described in the previous section.

Power plants connected to the PG&E gas system operate within a wholesale electricity market that spans the western United States (U.S.) and parts of Canada and Mexico. A substantial portion of electric generating capacity in this market is conventional (not pumped storage) hydroelectric. Gas-fired power plants make up most of the hydroelectric generation lost in dry years and generate less in wet years. Actual gas demand by power plants connected to the PG&E gas system was 598 MDth/d in 2008, a very dry year in northern California.

a. Modeling Methodology

PG&E's power plant gas demand forecast is based on results from the MarketBuilder program. (MarketBuilder is a registered trademark of MarketPoint Inc. of Los Altos, CA.) MarketBuilder is an economic-equilibrium program that has been applied to various markets

3. Summary of Proposed 2011 Rates

PG&E's proposed 2011 end-use rates are summarized in Table 11-1 and presented in detail in Appendix 11A following this chapter (2011-2014).

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
CLASS AVERAGE GAS ACCORD IV (GA IV) AND
PROPOSED 2011 RATES
ILLUSTRATIVE CLASS AVERAGE RATES
($/DTH)

Line No.	Customer Class	2010 Rates	Proposed 2011 Rates	$ Change(e)	% Change
1	Bundled-Retail Core(a)				
2	Residential	$13.854	$14.044	$0.190	1.4%
3	Small Commercial	$11.925	$12.109	$0.185	1.5%
4	Large Commercial	$9.747	$9.910	$0.163	1.7%
5	Uncompressed Core Natural Gas Vehicle (NGV)	$8.757	$8.913	$0.156	1.8%
6	Compressed Core NGV	$17.864	$17.943	$0.079	0.4%
7	Transport Only-Retail Core(b)				
8	Residential	$5.494	$5.580	$0.086	1.6%
9	Small Commercial	$3.672	$3.758	$0.086	2.3%
10	Large Commercial	$1.846	$1.932	$0.086	4.7%
11	Uncompressed Core NGV	$0.962	$1.048	$0.086	8.9%
12	Compressed Core NGV	$10.070	$10.156	$0.086	0.9%
13	Transport Only-Noncore(c)				
14	Industrial – Distribution	$1.505	$1.559	$0.054	3.6%
15	Industrial – Transmission	$0.581	$0.637	$0.056	9.7%
16	Industrial – Backbone	$0.371	$0.364	($0.007)	(1.9%)
17	Uncompressed Noncore NGV – Distribution	$1.387	$1.447	$0.060	4.4%
18	Uncompressed Noncore NGV – Transmission	$0.512	$0.573	$0.060	11.8%
19	Electric Generation – Distribution/Transmission	$0.203	$0.266	$0.063	31.0%
20	Electric Generation – Backbone	$0.043	$0.036	($0.007)	(15.5%)
21	Transport Only-Wholesale Core(d)				
22	Alpine Natural Gas	$0.254	$0.280	$0.026	10.2%
23	Coalinga	$0.246	$0.288	$0.042	17.1%
24	Island Energy	$0.452	$0.406	($0.046)	(10.2%)
25	Palo Alto	$0.179	$0.239	$0.060	33.4%
26	West Coast Gas – Castle	$0.847	$0.744	($0.104)	(12.2%)
27	West Coast Gas – Mather Distribution	$0.784	$0.835	$0.052	6.6%
28	West Coast Gas – Mather Transmission	$0.255	$0.307	$0.052	20.3%

(a) Bundled retail Core rates include proposed backbone transmission, local transmission and storage rate changes.
(b) Transport only retail Core rates include proposed local transmission rate changes.
(c) Transport only Noncore rates include proposed customer access charge and local transmission rate changes.
(d) Transport only wholesale Core rates include proposed customer access charge and local transmission rate changes.
(e) Dollar differences are due to rounding.

backbone transmission service. Core backbone transmission capacity costs receive balancing account treatment.

3. Proposals

a. Preliminary Cost Allocation

PG&E proposes to allocate the backbone transmission revenue requirement, with the exception of revenues associated with G-XF contracts, based on customer demands on the Redwood/Baja paths and the Silverado path. The G-XF revenue requirement will continue to be determined based on G-XF customers' firm contract quantities.

The cost allocation process excludes the costs, capacities, and demands associated with the Sacramento Municipal Utility District's (SMUD) equity interest in Lines 300 and 401. SMUD owns approximately 41.0 thousand decatherms per day (MDth/d) of Line 300 capacity and 43.4 MDth/d of Line 401 capacity.

Table 11-3 summarizes the customer demands and backbone capacities used to allocate costs to each path based on the forecast customer demands and Silverado path flows presented in Chapter 10. "Throughput Forecast" and the Line 401 capacity described in Chapter 2, "PG&E's Gas Transmission Facilities and Services."

TABLE 11-3
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED 2011 – 2014 BACKBONE COST ALLOCATORS
(MDTH/D)

Line No.	Rate Path	Lines 400/2, Lines 401(non G-XF), and Line 300/319 Cost Allocators	Common Cost Allocators	Line 401 Cost Allocators(a)
1	Redwood/Baja	1,892	1,892	
2	Silverado	52(b)	130	
3	Line 401 G-XF			92
4	Line 401 Non-G-XF			880
5	Total	1,944	2,022	972

(a) Used only to allocate Line 401 costs to G-XF contracts.
(b) The Silverado path receives a partial (40%) allocation of costs on Lines 400/2, 401, and 300/319. Therefore, the cost allocator is 40% of Silverado path flows.

Table 11-4 summarizes the costs initially allocated to each backbone transmission path based on the firm contract usage amounts shown in Table 11-3, above.

TABLE 11-4
PACIFIC GAS AND ELECTRIC COMPANY
INITIAL 2011 COST ALOCATION TO BACKBONE PATHS
($000)

Line No.	Rate Path	Line 400/2, Line 401(non G-XF), and Line 300/319	Common	G-XF	Total
1	Redwood/Baja	$169,461	$49,585		$219,046
2	Line 401 G-XF			$6,926	6,926
3	Silverado/Mission	4,657	3,407		8,064
4	Total	$174,118	$52,991	$6,926	$234,036

b. Final Cost Allocation and Rate Design

PG&E proposes to equalize Core Redwood/Baja rates and to equalize Noncore Redwood/Baja rates. The rationale for this change is described in Chapter 1, "Introduction and Policy." PG&E does not propose to equalize Core and Noncore rates or to eliminate the benefit of the Core's current vintage Line 400 Redwood rate. In addition, as explained in Chapter 2, backbone shippers will still hold capacity rights at specific receipt points on either the Redwood path or the Baja path.

PG&E will continue to set a single Silverado rate applicable to all Core and Noncore shippers. And, as noted above, PG&E is not proposing any changes to the Schedule G-XF rate.

As described in Chapter 1, PG&E also proposes to utilize a demand-based rate design. The steps in the proposed backbone cost allocation and rate design are as follows:

- **Step 1:** Calculate preliminary fully equalized Core/Noncore Redwood/Baja SFV and MFV rates for annual firm service (Schedule G-AFT). The cost allocation and rate calculations are based on the combined revenue requirements and forecast demands for the Redwood and Baja paths. Silverado costs and forecast demands are excluded from this calculation. Schedule G-XF costs and demands are also excluded.

- **Step 2:** In order to preserve the benefit of the Core's current vintage Line 400 Redwood rate, the preliminary Core Redwood/Baja rate derived in Step 1 is adjusted downward by the difference between what Core customers would pay for Redwood capacity under fully equalized Redwood rates and what they would pay under vintage Line 400 rates. The preliminary Noncore Redwood/Baja rate is then adjusted upward to make up for the reduction in Core revenues. As a result of this step, the cost allocation shown in Table 11-4 is modified as shown in Table 11-5.

TABLE 11-5
PACIFIC GAS AND ELECTRIC COMPANY
FINAL 2011 COST ALLOCATION TO BACKBONE PATHS
($000)

Line No.	Rate Path	Total
1	Core Redwood/Baja	$103,267
2	Noncore Redwood/Baja	115,778
3	Line 401 G-XF	6,926
4	Silverado/Mission	8,064
5	Total	$234,035

- **Step 3:** The cost allocations shown in Table 11-5 form the basis for Schedule G-AFT backbone rates. However, PG&E charges a 20 percent premium as-available service (Schedule G-AA), seasonal firm service (Schedule G-SFT), and certain negotiated firm services (Schedule G-NFT). Consequently, the Schedule G-AFT backbone rates derived from the cost allocation shown on Table 11-5 must be adjusted downward to offset this 20 percent premium. This adjustment is accomplished through an upward adjustment to throughput which, in effect, corrects the throughput for premium rate services to full (rather than premium) rate-equivalent throughput.
- **Step 4:** An upward adjustment is also made to backbone throughput to account for reservation charges paid for unused (or partially unused) firm contracts. Such reservation charges

produce revenues unconnected to any throughput, and thus cause an over-collection of backbone costs, absent this correction.

- **Step 5:** Finally, a downward adjustment is made to backbone throughput to reflect the rate discount for Pilkington North America described in Chapter 2.

The steps used to develop PG&E's proposed demand-based MFV 2011-2014 rates are shown in detail in PG&E's workpapers on pages WP 11-1 through WP 11-28. Workpapers showing the development of demand-based SFV 2011-2014 rates are found on pages WP 11-29 through WP 11-56.

c. Resulting Backbone Rates

PG&E's proposed G-AFT and G-XF backbone transmission rates are summarized in Table 11-6. A detailed summary of rates for all of PG&E's backbone transmission services is presented in Appendix 11A, Tables 11A-4 through 11A-10.

TABLE 11-6
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 PROPOSED G-AFT AND G-XF BACKBONE TRANSMISSION RATES
($/DTH)

Line No.	Path	GA IV 2010	2011	2012	2013	2014
1	G-AFT – Annual Firm Transportation					
2	Redwood Path – Core	$0.155	$0.271	$0.287	$0.308	$0.313
3	Baja Path – Core	$0.319	$0.271	$0.287	$0.308	$0.313
4	Redwood Path – Noncore	$0.294	$0.338	$0.357	$0.374	$0.372
5	Baja Path – Noncore	$0.319	$0.338	$0.357	$0.374	$0.372
6	Silverado and Mission Paths	$0.153	$0.148	$0.153	$0.161	$0.163
7	G-XF – Pipeline Expansion Firm Intrastate Transportation Service	$0.210	$0.207	$0.207	$0.200	$0.195

D. Backbone Level End-Use Rates (Ray Blatter)

Customers qualifying for backbone level service will continue to be exempt from paying the local transmission rate component in their end-user tariff. However, these customers will continue to be responsible for all other rate components in their end-user tariffs, including the CAC and the customer class charge. To the extent certain components of the customer class charge become the discounted deliveries. This discount adjustment results in Noncore local transmission rates that are $0.0007 per Dth higher than they would have otherwise been and Core local transmission rates that are $0.0008 per Dth higher than they would have otherwise been.

Table 11-9 presents PG&E's proposed 2011 through 2014 local transmission rates for Core and Noncore customers.

TABLE 11-9
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 PROPOSED LOCAL TRANSMISSION RATES
($/DTH)

Line No.	Customer Class	GA IV 2010(a)	2011	2012	2013	2014
1	Core	$0.369	$0.455	$0.484	$0.509	$0.546
2	Noncore (Including Wholesale)	$0.160	$0.220	$0.233	$0.257	$0.272

(a) The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for 2 of 5 of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement. (See Appendix 11A, Table 11A-13).

G. Transmission-Level Customer Access Charges (Ray Blatter)

1. Summary

PG&E proposes to update the Noncore transmission-level CAC to reflect the updated CAC revenue requirement developed in this case, and to make various other adjustments to the CAC rates. In the future, PG&E proposes that all CAC rate design matters be addressed in PG&E's BCAP proceedings, rather than GT&S rate cases. However, the CAC revenue requirement will continue to be determined in GT&S rate cases.

2. Background

The CAC recovers the costs of providing and maintaining a customer's service connection including the service line, regulator, meter and account services. Prior to Gas Accord I, PG&E's CAC revenue requirement was set in GRC proceedings and allocated to customer classes based on each class's customer marginal cost revenues in BCAPs. Beginning with Gas Accord I, CAC costs for transmission-level Noncore customers have been excluded from PG&E's GRC and BCAP proceedings.

TABLE 11A-1
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE END-USE CLASS AVERAGE RATES ($/DTH)(a)

Line No.		2010 Rates(b)	Proposed Rates 1/1/2011	$ Change(c)	% Change
1	**Core Retail Bundled Service(d)**				
2	Residential Non-CARE**/***	13.854	14.044	0.190	1.4%
3	Small Commercial Non-CARE**	11.925	12.110	0.185	1.5%
4	Large Commercial	9.747	9.910	0.163	1.7%
5	Uncompressed Core NGV	8.757	8.913	0.156	1.8%
6	Compressed Core NGV	17.864	17.943	0.079	0.4%
7	**Core Retail Transport Only(e)**				
8	Residential Non-CARE**/***	5.494	5.580	0.086	1.6%
9	Small Commercial	3.672	3.758	0.086	2.3%
10	Large Commercial	1.846	1.932	0.086	4.7%
11	Uncompressed Core NGV	0.962	1.048	0.086	8.9%
12	Compressed Core NGV	10.070	10.156	0.086	0.9%
13	**Noncore Retail Transportation Only(e)**				
14	Industrial – Distribution	1.505	1.559	0.054	3.6%
15	Industrial – Transmission	0.581	0.637	0.056	9.7%
16	Industrial – Backbone	0.371	0.364	(0.007)	-1.9%
17	Uncompressed Noncore NGV – Distribution	1.387	1.447	0.060	4.4%
18	Uncompressed Noncore NGV – Transmission	0.512	0.573	0.060	11.8%
19	Electric Generation – Distribution/Transmission	0.203	0.266	0.063	31.0%
20	Electric Generation – Backbone	0.043	0.036	(0.007)	-15.5%
21	**Wholesale Transportation Only(e)**				
22	Alpine Natural Gas	0.254	0.280	0.026	10.2%
23	Coalinga	0.246	0.288	0.042	17.1%
24	Island Energy	0.452	0.406	(0.046)	-10.2%
25	Palo Alto	0.179	0.239	0.060	33.4%
26	West Coast Gas - Castle	0.847	0.744	(0.104)	-12.2%
27	West Coast Gas - Mather D	0.784	0.835	0.052	6.6%
28	West Coast Gas - Mather T	0.255	0.307	0.052	20.3%

Notes:

a. Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

b. 2010 rates are based on PG&E's 2009 Annual Gas True-Up Filing (Advice Letter 2971-G and 2971-G-A), 2004 BCAP Decision D.05-06-029 and the 2010 backbone, local transmission, transmission level customer access, and bundled storage rates approved in Gas Accord IV D.07-09-045. In order to isolate the effect of PG&E's rate proposals in this filing, 2010 rates do not include $22 million in attrition as approved in PG&E's 2007 GRC Decision No. 07-03-044, Appendix A.

c. Dollar differences are due to rounding.

d. PG&E's bundled gas service is for Core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding, are included in end use rates paid by bundled Core customers. Bundled service also includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, and Core brokerage. An illustrative annual 2009 weighted average cost of gas (WACOG) of $6.96 as filed in Advice Letter 2791-G/2791-G-A, adjusted for intrastate backbone usage charges, is assumed in all present and proposed bundled Core rates. Core bundled rates also includes the cost of transportation and delivery of gas from the Citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

e. PG&E's transportation-only gas service is for Core and Noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

TABLE 11A-3
PACIFIC GAS AND ELECTRIC COMPANY
2011 RATE DETAIL BY END-USE CUSTOMER CLASS, INCLUDING ILLUSTRATIVE COMPONENTS ($/DTH)

		Core(a)					Noncore Transportation							Wholesale Transportation						
							Industrial			Natural Gas Vehicle		Electric Gen								
Line No.		Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
1	End-Use Transportation:																			
2	Local Transmission and Rate Adders	0.455	0.455	0.455	0.455	0.455	0.220	0.220	0.000	0.220	0.220	0.220	0.000	0.220	0.220	0.220	0.220	0.220	0.220	0.220
3	Backbone Level End-Use Surcharge																			
4	Distribution(b)	4.005	1.938	0.645	0.272	9.396	0.864	0.050	0.000	0.864	0.050	0.017	0.017	0.000	0.000	0.000	0.000	0.382	0.528	0.000
5	Mandated Customer Programs and Other Charges:																			
6	Self Generation Incentive Program	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	CPUC Fee	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Balancing Accounts	0.451	0.366	0.081	0.025	0.025	0.006	0.002	0.002	0.006	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.002
9	Volumetric End-Use Rate	4.927	2.774	1.196	0.767	9.892	1.105	0.287	0.017	1.105	0.287	0.254	0.034	0.222	0.222	0.222	0.222	0.605	0.750	0.222
10	Customer/ Customer Access Charge(c)	0.000	0.539	0.048	0.017	0.000	0.072	0.017	0.015	0.078	0.021	0.012	0.003	0.058	0.066	0.184	0.017	0.139	0.085	0.085
11	Total End-Use Rate	4.927	3.313	1.244	0.785	9.892	1.177	0.305	0.032	1.183	0.309	0.266	0.036	0.280	0.288	0.406	0.239	0.744	0.835	0.307
12	Gas Public Purpose Program Surcharge	0.654	0.445	0.688	0.264	0.264	0.382	0.332	0.332	0.264	0.264	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	Total Rate	5.580	3.758	1.932	1.048	10.156	1.559	0.637	0.364	1.447	0.573	0.266	0.036	0.280	0.288	0.406	0.239	0.744	0.835	0.307
14	Procurement Charges for Core Bundled Customers:																			
15	Storage	0.176	0.162	0.106	0.102	0.102														
16	Backbone Capacity	0.251	0.222	0.123	0.077	0.000														
17	Backbone Usage	0.105	0.105	0.105	0.105	0.105														
18	WACOG(d)	6.965	6.965	6.965	6.965	6.965														
19	Interstate Capacity and Other	0.967	0.897	0.679	0.615	0.615														
20	Total Core Procurement	8.464	8.351	7.978	7.864	7.787														
21	Total Core Bundled Rates	14.044	12.109	9.910	8.913	17.943														

Notes:

a. Class average rates reflect load shape for bundled Core.
b. Distribution rates represent the annual class average.
c. Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.
d. Reflects the annual average 2009 WACOG of as filed in Advice Letter 2791-G/2791-G-A.
e. Dollar differences are due to rounding.

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TABLE 11A-4
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	4.337	8.005	8.738	9.360	9.607
3	Usage Charge	($/dth)	0.012	0.008	0.008	0.008	0.008
4	Total	($/dth @ Full	0.155	0.271	0.287	0.308	0.313
5		Contract)					
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	9.232	8.005	8.738	9.360	9.607
8	Usage Charge	($/dth)	0.015	0.008	0.008	0.008	0.008
9	Total	($/dth @ Full	0.319	0.271	0.287	0.308	0.313
10		Contract)					
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	8.733	10.057	10.923	11.387	11.440
13	Usage Charge	($/dth)	0.007	0.007	0.008	0.008	0.008
14	Total	($/dth @ Full	0.294	0.338	0.357	0.374	0.372
15		Contract)					
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	9.232	10.057	10.923	11.387	11.440
18	Usage Charge	($/dth)	0.015	0.007	0.008	0.008	0.008
19	Total	($/dth @ Full	0.319	0.338	0.357	0.374	0.372
20		Contract)					
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	4.483	4.412	4.562	4.821	4.870
23	Usage Charge	($/dth)	0.006	0.003	0.003	0.003	0.003
24	Total	($/dth @ Full	0.153	0.148	0.153	0.161	0.163
25		Contract)					

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-5
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	3.329	5.727	6.002	6.391	6.498
3	Usage Charge	($/dth)	0.046	0.083	0.089	0.098	0.099
4	Total	($/dth @ Full	0.155	0.271	0.287	0.308	0.313
5		Contract)					
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	7.004	5.727	6.002	6.391	6.498
8	Usage Charge	($/dth)	0.089	0.083	0.089	0.098	0.099
9	Total	($/dth @ Full	0.319	0.271	0.287	0.308	0.313
10		Contract)					
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	5.070	6.625	7.007	7.357	7.392
13	Usage Charge	($/dth)	0.127	0.121	0.127	0.132	0.129
14	Total	($/dth @ Full	0.294	0.338	0.357	0.374	0.372
15		Contract)					
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	7.004	6.625	7.007	7.357	7.392
18	Usage Charge	($/dth)	0.089	0.121	0.127	0.132	0.129
19	Total	($/dth @ Full	0.319	0.338	0.357	0.374	0.372
20		Contract)					
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	3.084	3.049	3.144	3.316	3.366
23	Usage Charge	($/dth)	0.052	0.048	0.049	0.052	0.052
24	Total	($/dth @ Full	0.153	0.148	0.153	0.161	0.163
25		Contract)					

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-6
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
SEASONAL RATES (SFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	10.480	9.606	10.486	11.232	11.529
3	Usage Charge	($/dth)	0.008	0.009	0.009	0.010	0.010
4	Total	($/dth @ Full	0.353	0.326	0.344	0.370	0.376
5		Contract)					
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	11.078	9.606	10.486	11.232	11.529
8	Usage Charge	($/dth)	0.018	0.009	0.009	0.010	0.010
9	Total	($/dth @ Full	0.383	0.326	0.344	0.370	0.376
10		Contract)					
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	10.480	12.068	13.107	13.664	13.728
13	Usage Charge	($/dth)	0.008	0.009	0.009	0.009	0.009
14	Total	($/dth @ Full	0.353	0.406	0.428	0.448	0.446
15		Contract)					
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	11.078	12.068	13.107	13.664	13.728
18	Usage Charge	($/dth)	0.018	0.009	0.009	0.009	0.009
19	Total	($/dth @ Full	0.383	0.406	0.428	0.448	0.446
20		Contract)					
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	5.379	5.294	5.474	5.785	5.844
23	Usage Charge	($/dth)	0.007	0.003	0.003	0.003	0.004
24	Total	($/dth @ Full	0.184	0.177	0.183	0.194	0.196
25		Contract)					

Notes:

a. Firm Seasonal rates are 120 percent of Firm Annual rates.

b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e. Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f. Dollar differences are due to rounding.

TABLE 11A-7
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
SEASONAL RATES (SFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Reservation Charge	($/dth/mo)	6.084	6.872	7.202	7.669	7.798
3	Usage Charge	($/dth)	0.153	0.100	0.107	0.118	0.119
4	Total	($/dth @ Full	0.353	0.326	0.344	0.370	0.376
5		Contract)					
6	**Baja Path - Core**						
7	Reservation Charge	($/dth/mo)	8.404	6.872	7.202	7.669	7.798
8	Usage Charge	($/dth)	0.106	0.100	0.107	0.118	0.119
9	Total	($/dth @ Full	0.383	0.326	0.344	0.370	0.376
10		Contract)					
11	**Redwood Path - Noncore**						
12	Reservation Charge	($/dth/mo)	6.084	7.950	8.408	8.828	8.871
13	Usage Charge	($/dth)	0.153	0.145	0.152	0.158	0.155
14	Total	($/dth @ Full	0.353	0.406	0.428	0.448	0.446
15		Contract)					
16	**Baja Path - Noncore**						
17	Reservation Charge	($/dth/mo)	8.404	7.950	8.408	8.828	8.871
18	Usage Charge	($/dth)	0.106	0.145	0.152	0.158	0.155
19	Total	($/dth @ Full	0.383	0.406	0.428	0.448	0.446
20		Contract)					
21	**Silverado and Mission Paths**						
22	Reservation Charge	($/dth/mo)	3.701	3.659	3.773	3.979	4.039
23	Usage Charge	($/dth)	0.062	0.057	0.059	0.063	0.063
24	Total	($/dth @ Full	0.184	0.177	0.183	0.194	0.196
25		Contract)					

Notes:

a. Firm Seasonal rates are 120 percent of Firm Annual rates.

b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d. Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e. Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f. Dollar differences are due to rounding.

TABLE 11A-8
PACIFIC GAS AND ELECTRIC COMPANY
AS-AVAILABLE BACKBONE TRANSPORTATION
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Redwood Path - Core**						
2	Usage Charge	($/dth)	0.353	0.326	0.344	0.370	0.376
3	**Baja Path - Core**						
4	Usage Charge	($/dth)	0.383	0.326	0.344	0.370	0.376
5	**Redwood Path - Noncore**						
6	Usage Charge	($/dth)	0.353	0.406	0.428	0.448	0.446
7	**Baja Path - Noncore**						
8	Usage Charge	($/dth)	0.383	0.406	0.428	0.448	0.446
9	**Silverado Path**						
10	Usage Charge	($/dth)	0.184	0.178	0.183	0.194	0.196
11	**Mission Path**						
12	Usage Charge	($/dth)	0.000	0.000	0.000	0.000	0.000

Notes:

a. As-Available rates are 120 percent of Firm Annual rates.

b. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c. Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d. Dollar differences are due to rounding.

TABLE 11A-9
PACIFIC GAS AND ELECTRIC COMPANY
BACKBONE TRANSPORTATION
ANNUAL RATES (AFT-OFF)
OFF-SYSTEM DELIVERIES

Line No.			GA IV 2010	2011	2012	2013	2014
1	**SFV Rate Design**						
2	**Redwood, Silverado and Mission Paths Off-System**						
3	Reservation Charge	($/dth/mo)	8.733	10.057	10.923	11.387	11.440
4	Usage Charge	($/dth)	0.007	0.007	0.008	0.008	0.008
5	Total	($/dth @ Full	0.294	0.338	0.357	0.374	0.372
6		Contract)					
7	**Baja Path Off-System**						
8	Reservation Charge	($/dth/mo)	9.232	10.057	10.923	11.387	11.440
9	Usage Charge	($/dth)	0.015	0.007	0.008	0.008	0.008
10	Total	($/dth @ Full	0.319	0.338	0.357	0.374	0.372
11		Contract)					
12	**MFV Rate Design**						
13	**Redwood, Silverado and Mission Paths Off-System**						
14	Reservation Charge	($/dth/mo)	5.070	6.625	7.007	7.357	7.392
15	Usage Charge	($/dth)	0.127	0.121	0.127	0.132	0.129
16	Total	($/dth @ Full	0.294	0.338	0.357	0.374	0.372
17		Contract)					
18	**Baja Path Off-System**						
19	Reservation Charge	($/dth/mo)	7.004	6.625	7.007	7.357	7.392
20	Usage Charge	($/dth)	0.089	0.121	0.127	0.132	0.129
21	Total	($/dth @ Full	0.319	0.338	0.357	0.374	0.372
22	**As-Available Service**						
23	**Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore**						
24	Usage Charge	($/dth)	0.353	0.406	0.428	0.448	0.446
25	**Mission Paths (From On-System Storage) Off-System**						
26	Usage Charge	($/dth)	0.000	0.000	0.000	0.000	0.000
27	**Baja Path Off-System - Noncore**						
28	Usage Charge	($/dth)	0.383	0.406	0.428	0.448	0.446

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

d. Dollar differences are due to rounding.

TABLE 11A-10
PACIFIC GAS AND ELECTRIC COMPANY
FIRM TRANSPORTATION
EXPANSION SHIPPERS – ANNUAL RATES (G-XF)
SFV RATE DESIGN

Line No.			GA IV 2010	2011	2012	2013	2014
1	**SFV Rate Design**						
2	Reservation Charge	($/dth/mo)	6.318	6.241	6.257	6.036	5.885
3	Usage Charge	($/dth)	0.002	0.002	0.002	0.002	0.002
4	Total	($/dth @ Full	0.210	0.207	0.207	0.200	0.195
5		Contract)					

Notes:

a. Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b. The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c. G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d. Dollar differences are due to rounding.

TABLE 11A-11
PACIFIC GAS AND ELECTRIC COMPANY
STORAGE SERVICES

Line No.			GA IV 2010	2011	2012	2013	2014
1	**Core Firm Storage (G-CFS)**						
2	Reservation Charge	($/dth/mo)	0.109	0.127	0.131	0.135	0.138
3	**Standard Firm Storage (G-SFS)**						
4	Reservation Charge	($/dth/mo)	0.135	0.251	0.253	0.258	0.260
5	**Negotiated Firm Storage (G-NFS)**						
6	Injection	($/dth/d)	15.634	6.309	6.360	6.467	6.518
7	Inventory	($/dth)	1.621	3.015	3.039	3.090	3.114
8	Withdrawal	($/dth/d)	11.787	21.845	22.021	22.389	22.566
9	**Negotiated As-Available Storage (G-NAS) - Maximum Rate**						
10	Injection	($/dth/d)	15.634	6.309	6.360	6.467	6.518
11	Withdrawal	($/dth/d)	11.787	21.845	22.021	22.389	22.566
12	**Market Center Services (Parking and Lending Services)**						
13	Maximum Daily Charge ($/Dth/d)		0.970	1.131	1.150	1.170	1.185
14	Minimum Rate (per transaction)		57.000	57.000	57.000	57.000	57.000

Notes:

a. Rates for storage services are based on the costs of storage injection, inventory and withdrawal.
b. Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.
c. Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.
d. Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.
e. Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g., inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.
f. Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.
g. The maximum charge for parking and lending is based on the annual cost of cycling 1 Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.
h. Gas Storage shrinkage will be applied in-kind on storage injections.
i. Dollar differences are due to rounding.

TABLE 11A-13
PACIFIC GAS AND ELECTRIC COMPANY
LOCAL TRANSMISSION RATES ($/DTH)

Line No.		GA IV 2010	2011	2012	2013	2014
1	**Base Rates:**					
2	Core Retail	0.337	0.455	0.484	0.509	0.546
3	Noncore Retail and Wholesale	0.146	0.220	0.233	0.257	0.272
4	**Rate Adders:**					
5	Core					
6	Line 138 (16 miles of 30"pipe)	0.017	0.000	0.000	0.000	0.000
7	Line 108 (11 miles of 24" pipe)	0.015	0.000	0.000	0.000	0.000
8	Line 406 (15 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
9	Line 407 (4 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
10	Line 407 (8 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
11	Total	0.033	0.000	0.000	0.000	0.000
12	Noncore Retail & Wholesale					
13	Line 138 (16 miles of 30"pipe)	0.008	0.000	0.000	0.000	0.000
14	Line 108 (11 miles of 24" pipe)	0.007	0.000	0.000	0.000	0.000
15	Line 406 (15 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
16	Line 407 (4 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
17	Line 407 (8 miles of 30" pipe)	0.000	0.000	0.000	0.000	0.000
18	Total	0.014	0.000	0.000	0.000	0.000
19	**Total Base plus Adder:**					
20	Core Retail	0.369	0.455	0.484	0.509	0.546
21	Noncore Retail and Wholesale	0.160	0.220	0.233	0.257	0.272

Notes:

a. The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for two of five of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX 11B
TRADITIONAL BACKBONE RATE CALCULATION

A. Scope and Purpose (Carl Orr)

As discussed in Chapter 1, "Introduction and Policy," and Chapter 11, "Cost Allocation and Rate Design," Pacific Gas and Electric Company (PG&E or the Company) is proposing two significant changes to its backbone rate design. First, PG&E is proposing to equalize the Core Redwood and Core Baja rates, and the Noncore Redwood (excluding Schedule G-XF) and Noncore Baja rates. Second, PG&E is proposing a demand based backbone rate design rather than the traditional system average load factor based rate design. This appendix provides a traditional backbone rate calculation—without equalization of any rates, and employing a system average load factor—as a point of reference for PG&E's proposals in Chapter 11.

B. Background (Carl Orr)

As explained in Chapter 2, "Gas Transmission Facilities and Services," PG&E provides backbone transmission service on four backbone paths: Redwood; Baja; Silverado; and Mission. For rate design purposes, PG&E further divides the Redwood path into three sub-paths: Core Redwood; Noncore Redwood; and Schedule G-XF. The rate design process also disregards the Mission path. No costs are allocated to the Mission path because the Mission as-available rate is zero. Although the Mission firm rate is not zero (it is set equal to the Silverado firm rate), no customers are forecasted to take Mission firm service.

Under traditional utility rate design, the allocated costs for each backbone path would be divided by the adopted throughput or demand for the path to get the path rate. However, PG&E forecasts total end-use demand, not path-by-path throughputs. Developing end-use demand projections is a complex process in its own right. To take the next step and forecast which supply sources and backbone paths will serve that demand would be even more difficult.[1] Therefore, since the beginning of the Gas Accord structure in 1998, PG&E has designed backbone rates based on a system average backbone load factor. The system average load factor is calculated as total backbone throughput divided by total backbone capacity, plus various adjustments. Thus, instead of dividing allocated costs by a forecast of path demand, PG&E divides allocated costs by the product of the path capacity and the system average load factor:

$$\text{Path Rate} = \frac{\text{Allocated Path Costs (\$ '000)}}{\text{Path Capacity (MDth/d)} \times \text{System Average Load Factor (\%)} \times \text{365 d}}$$

In effect, this methodology assumes that all paths are used proportionally to serve demand on PG&E's system. Another way of thinking about the methodology is it *de-averages* the numerator (costs) of the backbone rate calculation by path, but *averages* the denominator (throughput).

The remainder of this appendix describes the system average backbone load factor calculation (Section C) and the traditional backbone cost allocation and rate design employing the backbone load factor (Section D).

C. Calculation of System Average Backbone Load Factor (Carl Orr)

1. Introduction

This section combines the various gas demand forecasts from Chapter 10 and the various backbone capacities from Chapter 2 to develop the system average backbone load factor traditionally used to calculate PG&E's backbone rates. This section also provides details of several load factor adjustments that are necessary to ensure that load factor based backbone rates fully collect, but do not over-collect, adopted backbone costs at adopted demand levels.

2. Load Factor Calculation

Table 11B-1 shows the backbone load factor calculation for traditional backbone rate design for 2011 through 2014.

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[1] As explained in Chapter 11, PG&E is proposing a demand based backbone rate design because equalization of the rates for all Core service, and for substantially all Noncore service (excluding G-XF and Silverado), lends itself to use of the Core and Noncore demand forecasts as path throughput forecasts.

TABLE 11B-1
PACIFIC GAS AND ELECTRIC COMPANY
SYSTEM AVERAGE BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN

Line		2011	2012	2013	2014
1	**Backbone Demand (MDth/d)**				
2	Core	793	802	805	802
3	Core distribution shrinkage	23	23	23	23
4	Noncore industrial	465	468	469	470
5	Wholesale	10	10	10	10
6	Electric generation	509	533	522	543
7	Cogeneration	201	202	201	201
8	Subtotal, on-system	2,001	2,038	2,031	2,050
9	G-XF off-system	86	80	80	80
10	Non-G-XF off-system (full-rate-equivalent throughput) **(a)**	29	29	30	30
11	Subtotal, off-system	116	109	110	111
12	TOTAL	2,117	2,148	2,141	2,160
13	Remove G-XF contracts	(92)	(86)	(86)	(86)
14	Adjust for Pilkington Baja on-system discount **(b)**	(1)	(1)	(1)	(1)
15	Adjust for G-AA, G-SFT, and G-NFT premiums **(c)**	55	34	32	36
16	Adjust for reservation charges for un-used firm contracts **(d)**	48	49	49	49
17	Adjust for disproportionate path flows **(e)**	(39)	(19)	17	28
18	Subtotal, adjustments	(28)	(23)	11	26
19	TOTAL, ADJUSTED	**2,089**	**2,125**	**2,152**	**2,186**
20	**Backbone Capacity (MDth/d @ Delivery Point)**				
21	Redwood Line 401	1,015	1,015	1,015	1,015
22	Redwood Line 400	1,033	1,033	1,033	1,033
23	Baja Line 300	1,040	1,068	1,068	1,068
24	Silverado "capacity"	193	192	189	186
25	TOTAL	3,282	3,309	3,306	3,303
26	Remove G-XF contracts	(92)	(86)	(86)	(86)
27	Remove SMUD equity capacity, Line 401	(43)	(43)	(43)	(43)
28	Remove SMUD equity capacity, Line 300	(41)	(41)	(41)	(41)
29	Subtotal, adjustments	(176)	(170)	(170)	(170)
30	TOTAL, ADJUSTED	**3,106**	**3,139**	**3,136**	**3,133**
31	Memo: Silverado flow forecast	130	130	130	130
32	**Backbone Load Factor**	**67.26%**	**67.69%**	**68.62%**	**69.78%**

The on-system demands in Lines 1 through 8 of Table 11B-1 are taken from Chapter 10, except that Core distribution shrinkage (line 3) is added, based on a shrinkage rate of 2.9 percent. Off-system throughput is shown on lines 9 through 11. This forecast includes non-G-XF off-system throughput (expressed as full-rate-equivalent throughput), which is discussed further in the next section. Total throughput is shown on line 12. Various throughput adjustments are shown on lines 13 through 18, which are discussed in detail in the next section. Line 19 shows total adjusted throughput.

The backbone throughput represented on lines 1 through 19 of Table 11B-1 excludes Mission path throughput. The Mission path is used

TABLE 11B-2
PACIFIC GAS AND ELECTRIC COMPANY
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN

		2011	2012	2013	2014
1	**(a) Calculate full rate equivalent non-G-XF off-system throughput**				
2	Forecasted revenues ($ '000/yr)	$3,277	$3,277	$3,277	$3,277
3	Redwood G-AFT rate ($/Dth)	$0.305	$0.309	$0.302	$0.296
4	Full rate equivalent throughput (MDth/d)	**29**	**29**	**30**	**30**
5	**(b) Adjust for Pilkington Baja on-system discount**				
6	Throughput adjustment (MDth/d)	**(1)**	**(1)**	**(1)**	**(1)**
7	(Note: The details of this adjustment are confidential.)				
8	**(c) Adjust for G-AA, G-SFT, and G-NFT premiums**				
9	G-AA throughput - Core (MDth/d)	3	3	3	3
10	G-AA throughput - Noncore (MDth/d)				
11	Total on-system throughput	2,001	2,038	2,031	2,050
12	EAD throughput	8	0	0	0
13	G-XF on-system throughput	5	5	5	5
14	Firm throughput excl EAD and G-XF	1,902	1,918	1,918	1,918
15	G-AA throughput, Core	3	3	3	3
16	G-AA throughput, Noncore (determined residually)	83	112	105	124
17	G-SFT throughput - Core				
18	Core G-SFT MDQ (annualized MDth/d)	72	55	55	55
19	Core G-SFT utilization rate	96.4%	96.4%	96.4%	96.4%
20	Core G-SFT throughput (MDth/d)	69	53	53	53
21	G-SFT and G-NFT throughput - Noncore				
22	Noncore G-SFT and G-NFT MDQ (annualized MDth/d)	126	0	0	0
23	Noncore G-SFT and G-NFT average utilization rate	96.2%	96.2%	96.2%	96.2%
24	Noncore G-SFT and G-NFT throughput (MDth/d)	121	0	0	0
25	TOTAL (MDth/d)	276	168	161	180
26	Rate premium	20%	20%	20%	20%
27	Premium adjustment (MDth/d)	**55**	**34**	**32**	**36**
28	**(d) Adjust for reservation charges for unused firm contracts**				
29	Total firm contract MDQ excl EAD and G-XF (MDth/d)	1,974	1,991	1,991	1,991
30	Average firm contract utilization rate excl G-XF and EAD	96.3%	96.3%	96.3%	96.3%
31	Unused firm MDQ (MDth/d)	73	73	73	73
32	Average reservation portion of MFV rate	66.7%	66.5%	66.3%	66.7%
33	Unused firm contract adjustment (MDth/d)	**48**	**49**	**49**	**49**

TABLE 11B-2
PACIFIC GAS AND ELECTRIC COMPANY
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR, 2011-2014
TRADITIONAL BACKBONE RATE DESIGN

(CONTINUED)

		2011	2012	2013	2014
34	**(e) Adjust for disproportionate path flows**				
35	Redwood Core capacity (MDth/d)	616	616	616	616
36	Throughput at load factor (MDth/d)	414	417	422	430
37	Expected Redwood Core utilization rate (incl brokering)	98.7%	98.7%	98.7%	98.7%
38	Expected Redwood Core throughput (MDth/d)	608	608	608	608
39	Throughput shift to Redwood Core path (MDth/d)	194	191	185	178
40	Redwood Core rate as percent of system average rate	58.0%	59.2%	58.1%	59.0%
41	Percent difference relative to system average rate	-42.0%	-40.8%	-41.9%	-41.0%
42	Throughput adjustment (MDth/d)	(81)	(78)	(78)	(73)
43	Baja capacity (MDth/d, excl SMUD equity)	999	1,027	1,027	1,027
44	Throughput at load factor (MDth/d)	672	695	705	717
45	Expected Baja utilization rate (incl brokering)	83.5%	83.5%	83.5%	83.5%
46	Expected Baja throughput (MDth/d)	834	858	858	858
47	Throughput shift to Baja path (MDth/d)	162	162	153	141
48	Baja rate as percent of system average rate	126.0%	128.4%	136.5%	138.4%
49	Percent difference relative to system average rate	26.0%	28.4%	36.5%	38.4%
50	Throughput adjustment (MDth/d)	42	46	56	54
51	Redwood Noncore capacity (MDth/d; excl G-XF and SMUD equity)	1,298	1,304	1,304	1,304
52	Throughput at load factor (MDth/d)	873	883	895	910
53	Expected Redwood Noncore throughput (determined residually, MDth/d)	453	466	460	479
54	Throughput shift to Redwood Noncore path (MDth/d)	(420)	(416)	(435)	(431)
55	Redwood Noncore rate as percent of system average rate	99.9%	96.8%	91.0%	89.1%
56	Percent difference relative to system average rate	-0.1%	-3.2%	-9.0%	-10.9%
57	Throughput adjustment (MDth/d)	0	13	39	47
58	Total throughput adjustment (MDth/d)	**(39)**	**(19)**	**17**	**28**
59	**Backbone Rate Inputs (G-AFT, $/Dth)**				
60	System average rate (excl Silverado and G-XF)	$0.306	$0.319	$0.332	$0.332
61	Redwood Core rate	$0.177	$0.189	$0.193	$0.196
62	Redwood Noncore rate	$0.305	$0.309	$0.302	$0.296
63	Baja rate	$0.385	$0.410	$0.453	$0.460

To understand the various throughput adjustments, it is necessary to understand how the system average backbone load factor is used in the traditional backbone rate setting process. It is used to calculate annual firm transmission (G-AFT) rates. All other backbone rates or rate caps—for seasonal firm, negotiated firm, as-available, and negotiated as-available services—are derived from multiples of the annual firm rate. For example, the as-available rate for a given path is 120 percent of the annual firm rate for that path. Thus, the “raw” system average load factor must be adjusted for transmission services that PG&E expects to provide at rates above or below the annual firm rate.

In addition, to the extent the throughputs on PG&E’s various backbone paths are expected to deviate from proportional throughputs to SMUD under an equity ownership arrangement have been excluded from the cost of service.

TABLE 11B-3
PACIFIC GAS AND ELECTRIC COMPANY
2011 FIRM CAPACITIES FOR ALLOCATING COSTS TO BACKBONE PATHS (EXCLUDES SMUD EQUITY INTERESTS) – TRADITIONAL BACKBONE RATE DESIGN
(MDth/d)

Line No.	Rate Path	Redwood Core Vintage	Other Redwood (Noncore)	Line 401 (Included in Other Redwood)	Baja	Common
1	Redwood – Core Vintage	615.60				615.60
2	Redwood		1,297.97			1,297.97
3	L401 Non G-XF			880.17		
4	L401 G-XF			91.83		
5	Baja				999.01	999.01
6	Silverado/Mission		38.65		38.65	193.27
7	Total	615.60	1,336.62	972.00	1,037.66	3,105.84

Table 11B-4 summarizes the costs allocated to each backbone transmission path based on the firm backbone capacities shown in Table 11B-3.

TABLE 11B-4
PACIFIC GAS AND ELECTRIC COMPANY
2011 COST ALLOCATION TO BACKBONE PATHS (EXCLUDES SMUD EQUITY INTERESTS) – TRADITIONAL BACKBONE RATE DESIGN
($000)

Line No.	Rate Path	Redwood Core Vintage	Other Redwood (Noncore)	Line 401 (Included in Other Redwood)	Baja	Common	Total Backbone
1	Redwood – Core Vintage	$16,270				$10,503	$26,773
2	Redwood – Noncore		$75,186			22,146	97,331
3	L401 Non G-XF			$66,382			
4	L401 G-XF			6,926			6,926
5	Baja				$77,427	17,045	94,472
6	Silverado/Mission		2,239		2,996	3,297	8,532
7	Total	$16,270	$77,425	$73,308	$80,423	$52,991	$234,035

TABLE 11B-5
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – SFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	Redwood – Core						
2	Reservation Charge	($/Dth/mo)	4.337	5.296	5.654	5.770	5.866
3	Usage Charge	($/Dth)	0.012	0.003	0.003	0.003	0.003
4	Total	($/Dth @ Full Contract)	0.155	0.177	0.189	0.193	0.196
5	Redwood Path						
6	Reservation Charge	($/Dth/mo)	8.733	9.216	9.322	9.111	8.921
7	Usage Charge	($/Dth)	0.007	0.003	0.003	0.003	.003
8	Total	($/Dth @ Full Contract)	0.294	0.306	0.309	0.302	0.296
9	Baja Path						
10	Reservation Charge	($/Dth /mo)	9.232	11.196	11.952	13.266	13.471
11	Usage Charge	($/Dth)	0.015	0.017	0.017	0.017	0.017
12	Total	($/Dth @ Full Contract)	0.319	0.385	0.410	0.453	0.460
13	Silverado and Mission Paths						
14	Reservation Charge	($/Dth /mo)	4.483	5.348	5.527	5.787	5.805
15	Usage Charge	($/Dth)	0.006	0.004	0.004	0.004	0.004
16	Total	($/Dth @ Full Contract)	0.153	0.180	0.186	0.194	0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) Backbone transmission charges are based on 67.26 percent, 67.69 percent, 68.62 percent, 69.78 percent load factors for 2011, 2012, 2013 and 2014, respectively.

(c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

(e) Dollar differences are due to rounding.

TABLE 11B-6
PACIFIC GAS AND ELECTRIC COMPANY
FIRM BACKBONE TRANSPORTATION
ANNUAL RATES (AFT) – MFV RATE DESIGN
ON-SYSTEM TRANSPORTATION SERVICE

Line No.			GA IV 2010	2011	2012	2013	2014
1	Redwood – Core						
2	Reservation Charge	($/Dth/mo)	3.329	3.831	4.069	4.144	4.202
3	Usage Charge	($/Dth)	0.046	0.051	0.055	0.057	0.058
4	Total	($/Dth @ Full Contract)	0.155	0.177	0.189	0.193	0.196
5	Redwood Path						
6	Reservation Charge	($/Dth/mo)	5.070	5.644	5.788	5.758	5.729
7	Usage Charge	($/Dth)	0.127	0.120	0.119	0.113	0.107
8	Total	($/Dth @ Full Contract)	0.294	0.305	0.309	.0.302	0.296
9	Baja Path						
10	Reservation Charge	($/Dth/mo)	7.004	.8.399	8.729	9.418	9.540
11	Usage Charge	($/Dth)	0.089	0.109	0.123	0.143	0.146
12	Total	($/Dth @ Full Contract)	0.319	0.385	0.410	0.453	0.460
13	Silverado and Mission Paths						
14	Reservation Charge	($/Dth /mo)	3.084	3.707	3.810	3.972	4.004
15	Usage Charge	($/Dth)	0.052	0.058	0.060	0.064	0.063
16	Total	($/Dth @ Full Contract)	0.153	0.180	0.186	0.194	0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) Backbone transmission charges are based on 67.26 percent, 67.69 percent, 68.62 percent, 69.78 percent load factors for 2011, 2012, 2013 and 2014, respectively.

(c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

(e) Dollar differences are due to rounding.

TABLE 11B-7
PACIFIC GAS AND ELECTRIC COMPANY
FIRM TRANSPORTATION
EXPANSION SHIPPERS – ANNUAL RATES (G-XF)
SFV RATE DESIGN

Line No.			GA IV 2010	2011	2012	2013	2014
1	SFV Rate Design						
2	Reservation Charge	($/Dth/mo)	6.318	6.241	6.257	6.036	5.885
3	Usage Charge	($/Dth)	0.002	0.002	0.002	0.002	0.002
4	Total	($/Dth @ Full Contract)	0.210	0.207	0.207	0.200	0.195

(a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

(b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

(c) G-XF charges are based on the embedded cost of Line 401 and reflect a 100 percent load factor for reservation charges and a 95 percent load factor for usage charges.

(d) Dollar differences are due to rounding.