ABAG POWER Executive Committee Meeting No. 2011-02
April 20, 2011 (12 Noon - 2:00 p.m.)

Association of Bay Area Governments
101 Eighth Street, Conference Room B
Oakland, CA 94607

AGENDA*

1. **Welcome and Introductions**

2. **Public Comments**

3. **Approve Summary Minutes of Executive Committee Meeting**
Action:
ATTACHMENT 3A – SUMMARY MINUTES OF FEBRUARY 16, 2011

4. **Appointments to Executive Committee**
Action: Chairman's appointments to the Executive Committee: Beth Balita representing the County of Contra Costa, and Erwin Blancaflor representing the City of Hercules.

5. **Report on Natural Gas Program**
Information: Staff will review recent gas operation, including gas purchases; the program's long-term hedge position; gas imbalances; and other miscellaneous program items.
ATTACHMENT 5A – MONTHLY SUMMARY OF OPERATIONS FY 10-11
ATTACHMENT 5B – MARKET PRICE CHART
ATTACHMENT 5C – GAS HEDGE CHART
ATTACHMENT 5D – CTA SETTLEMENT AGREEMENT

6. **Preliminary FY2011-12 Budget**
Action: Staff will review a preliminary budget for FY2011-12.
ATTACHMENT 6A – OPERATING BUDGET
ATTACHMENT 6B – LEVELIZED CHARGE CALCULATION

7. **ABAG Energy Programs Update**
Information: Staff will update members on the status of the following programs:
    - ABAG Green Communities (Partnership with PG&E)
    - Energy Upgrade California (Retrofit Bay Area)
    - DOE Better Buildings Program
    - Electric Vehicle (EV) Projects

*The Committee may take action on any item on this agenda

Mailing Address: P.O. Box 2050 Oakland, California 94604-2050 (510) 464-7900 Fax: (510) 464-8468
info@abag.ca.gov Joseph P. Bort MetroCenter 101 Eighth Street Oakland, California 94607-4756

 Attachment 3A

SUMMARY MINUTES

ABAG Power Executive Committee
Regular Meeting 2011-01
February 16, 2011
Metro Center, ABAG's Conference Room B
101 8th Street, Oakland, CA 94607

WELCOME AND INTRODUCTIONS

Chairman Chris Schroeder opened the meeting with introductions at 12:05 p.m.

Committee Representatives	**Jurisdictions**
Mark Armstrong	City of Santa Rosa
Chris Schroeder (Chairman)	City of Milpitas
Richard Sealana	City of Union City
Members Absent	
Jennifer Mennucci	Golden Gate Bridge District
Ron Popp	City of Millbrae
Others Present	
Terry Mann	Representing the County of Contra Costa
Staff Present	
Herbert Pike	ABAG
Ken Moy	ABAG
Jerry Lahr	ABAG POWER

PUBLIC COMMENTS & ANNOUNCEMENTS

There were no public comments.

It was announced that two members of the Executive Committee - Raj Pankhania (City of Hercules) and Michael Lango (County of Contra Costa) - were no longer on staff at their respective agencies. These positions on the committee have become vacant.

APPROVAL OF SUMMARY MINUTES OF DECEMBER 15, 2010

Motion was made by Sealana/S/Armstrong/C/3:0:0 to approve the Summary Minutes of December 15, 2010 Executive Committee Meeting.

APPOINTMENT TO EXECUTIVE COMMITTEE
The appointment of Beth Balita to the Executive Committee representing the County of Costra Costa was put on hold until a future meeting.

Lahr informed the committee that membership in the ABAG POWER Executive Committee had fallen from seven official members down to five official members, although this still meets the requirements of ABAG POWER bylaws.

REPORT ON NATURAL GAS PROGRAM
Monthly Summary of Operations FY 10-11
Lahr provided the members with the Monthly Summary of Operations report for FY 2010-11. He said that the cumulative savings in comparison with PG&E as of October 31, 2010 is a low -0.4% as compared to a significant -16.3% at the end of June, 2010.

A fixed priced natural gas contract was put into place for the period April 1, 2011 to March 31, 2012.

Historical Market Price Chart
Lahr presented a chart showing historical natural gas market prices indicating the monthly and daily market price indices at PG&E Citygate, along with the futures market prices.

Gas Hedge Chart
Lahr provided the members with a chart showing ABAG POWER's long-term gas purchases. Pkg.7 indicated the new long term purchase, Malin: $4.465 for the period April 1, 2011 to March 31, 2012. He is holding off buying longer term contracts past March, 2012 due to expected changes in the regulations related to CTAs' obligations for gas transmission and storage.

Additional Imbalance Charge by PG&E
ABAG POWER had received correspondence from PG&E indicating that due to a glitch in their technical system in December, 2009, they had not charged CTAs for a day's worth of gas. For ABAG POWER, it represented approximately 20,000 therms (equivalent to about $9 - $10,000 at current prices).

CTA's discussed the matter with PG&E questioning why it took them nine months to notify the customers. PG&E is planning to add this to ABAG POWER's imbalance statement starting with their March, 2011 statement.

FY 2009-10 AUDITED FINANCIAL STATEMENTS
Motion was made by Sealana/S/Armstrong/C/3:0:0 to approve the audited financial statements for the year ending June 30, 2010 as presented.

Attachment 3A

ABAG ENERGY PROGRAMS UPDATE
Lahr provided the Committee with an update on ABAG's current energy–related funding proposals. These proposals/programs are:

- ABAG Green Communities (Partnership with PG&E)
- Energy Upgrade California (Retrofit Bay Area)
- DOE Better Buildings Program
- Electric Vehicle (EV) Projects

ADJOURNMENT
Chairman Schroeder adjourned the meeting at 1:05 p.m.

/vm

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*Example of a motion – *[Member No. 1/S/Member No. 2/roll call vote/C/8:0:0]* means Member No.1 motions, seconded by Member No.2, after roll call vote, motion carries, 8 = "yes" votes, 0 = "no" votes and 0 = abstention.

ABAG POWER Natural Gas Program

FY 2010-11 Monthly Summary of Operations

		Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
	days/mo.	31	31	30	31	30	31	31	28	31	30	31	30	
Gas Purchases[1]														
Purchase 1	Qty	15,500	15,500	15,000	15,500	15,000	15,500	15,498	13,749	15,500	15,000	15,500	15,000	182,247
	Price	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$4.47	$4.47	$4.47	
Purchase 2	Qty	15,500	15,500	15,000	15,500	15,000	15,500	15,500	14,000	15,500	15,000	15,500	15,000	182,500
	Price	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90	
Purchase 3	Qty	20,057	20,026	24,030	24,800	23,970	15,500	15,500	14,000	24,676				182,559
	Price	$4.28	$4.11	$3.37	$3.74	$3.57	$5.45	$5.45	$5.45	$3.83				
Purchase 4	Qty	5,450	7,800	7,650	17,350	36,200	24,769	26,013	22,344	25,000				172,576
	Price	$4.32	$3.99	$4.05	$3.89	$4.44	$4.35	$4.08	$4.19	$4.23				
Purchase 5	Qty						19,125	21,250	15,800					56,175
	Price						$4.34	$4.53	$4.15					
Total Quantity Purchased		56,507	58,826	61,680	73,150	90,170	90,394	93,761	79,893	80,676	30,000	31,000	30,000	776,057
Total Purchase Cost		$317,077	$321,139	$312,967	$367,871	$447,089	$482,953	$494,451	$421,274	$407,967	$155,475	$160,658	$155,475	$4,044,395
Backbone Shrinkage (Dths)		(527)	(527)	(570)	(589)	(570)	(589)	(467)	(417)	(465)				
Weighted Avg. Cost of Gas (WACOG) [2]		$5.66	$5.51	$5.12	$5.07	$4.99	$5.38	$5.30	$5.30	$5.09	$5.18	$5.18	$5.18	$5.21
Storage/Inventory														
Total Injections/ (Withdrawals)		7,151	8,635	8,534	14,720	13,811	(19,479)	(15,000)	(15,440)	(15,000)				(12,068)
Total Inventory Quantity (Dths)		34,219	42,854	51,388	66,108	79,919	60,440	45,440	30,000	15,000				
Total Inventory ($)		$210,432	$259,565	$306,499	$377,262	$447,355	$338,336	$254,374	$167,943	$83,971				
Gas Program Monthly Expenses (from Financial Reports)														
Cost of Energy Used[3]		$ 270,210	$ 272,003	$ 266,628	$ 297,108	$ 397,993	$ 590,473	$ 578,346	$ 507,630					$ 3,180,391
Program Operating Expenses[4]		25,117	30,816	29,535	32,367	30,770	25,785	18,498	27,813					220,701
Subtotal		$ 295,327	$ 302,819	$ 296,163	$ 329,475	$ 428,763	$ 616,258	$ 596,844	$ 535,443	$ -	$ -	$ -	$ -	$ 3,401,092
Rate ($/Dth)		$5.30	$5.37	$5.21	$5.10	$5.19	$5.99	$5.92	$6.35					$5.63
PG&E Pass-through costs[5]		68,342	126,842	223,275	150,229	164,512	335,626	282,561	285,690					1,637,077
Total ABAG POWER Cost		$ 363,669	$ 429,661	$ 519,439	$ 479,705	$ 593,275	$ 951,884	$ 879,405	$ 821,132					$ 5,038,169
Actual (metered) Gas Usage														
Core[6]		46,569	47,835	44,346	52,594	71,590	91,495	89,250	75,097					518,777
Non Core		9,138	8,571	12,552	12,017	11,079	11,404	11,602	9,245					85,608
Total Program Usage		55,707	56,407	56,898	64,611	82,669	102,898	100,852	84,342	0	0	0	0	604,384
ABAG POWER Total Core Rate		$ 6.77	$ 8.02	$ 10.24	$ 7.96	$ 7.48	$ 9.66	$ 9.08	$ 10.15					
PG&E Rate[7]														
Procurement Charge[8]		5.06	5.34	5.24	5.26	4.82	5.43	5.56	6.36	5.34	5.26			
Transportation/Other Charge[9]		1.47	2.65	5.03	2.86	2.30	3.67	3.17	3.80					
Total PG&E Rate		$ 6.53	$ 7.99	$ 10.28	$ 8.12	$ 7.12	$ 9.10	$ 8.73	$ 10.16	$ 5.34	$ 5.26	$ -	$ -	
Rate Comparison														
Monthly Rate Difference ($/Dth)		0.24	0.03	(0.04)	(0.16)	0.37	0.56	0.36	(0.01)					
Monthly Savings ($)		(11,362)	(1,592)	1,755	8,518	(26,132)	(50,852)	(31,979)	695					
Cumulative 'Savings' ($)		(11,362)	(12,954)	(11,199)	(2,681)	(28,814)	(79,666)	(111,645)	(110,950)					
Cumulative 'Savings' (%)		-3.7%	-1.9%	-1.0%	-0.2%	-1.4%	-2.7%	-3.0%	-2.5%					

ABAG POWER Natural Gas Program

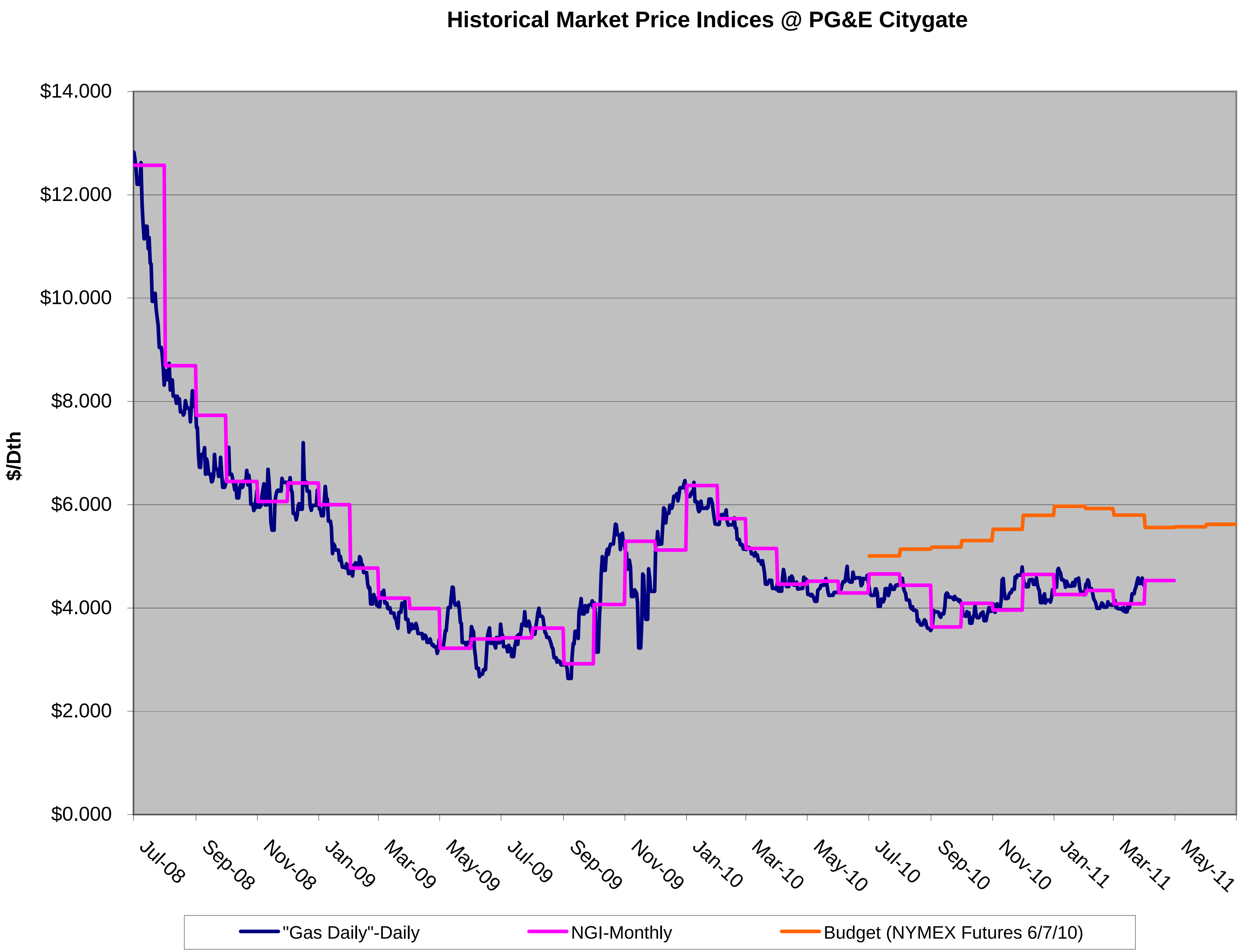
FY 2010-11 Monthly Summary of Operations

		Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Storage Gas Accounting														
Beginning Quantity		27,068												
Average Price		$6.04												
Beginning of Month	Qty	27,068	34,219	42,854	51,388	66,108	79,919	60,440	45,440	30,000	15,000	15,000	15,000	
Injections	Qty	0	0	188	260	2,699	0	0	0	0				
Storage Shrinkage	Qty			-4	-5	-53								
	Price	$0.00	$0.00	$5.12	$5.07	$4.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Imbalance Trades	Qty	7,151	8,635	8,350	14,465	11,165	-3,514	-1,400	-425					
	Price	$6.55	$5.69	$5.51	$4.80	$5.10	$5.59	$5.59	$5.59					
Withdrawals	Qty						15,965	13,600	15,015	15,000				
	Price	$6.04	$6.15	$6.06	$5.96	$5.71	$5.60	$5.60	$5.60	$5.60	$5.60			
End of Month	Qty	34,219	42,854	51,388	66,108	79,919	60,440	45,440	30,000	15,000	15,000	15,000	15,000	
	Avg. Pric	$6.15	$6.06	$5.96	$5.71	$5.60	$5.60	$5.60	$5.60	$5.60				
End of Month Inventory		$210,432	$259,565	$306,499	$377,262	$447,355	$338,336	$254,374	$167,943	$83,971				
Monthly Index Postings														
NGI Bidweek for PG&E Citygate		$4.66	$4.44	$3.63	$4.09	$3.96	$4.65	$4.26	$4.34	$4.08	$4.53			
Gas Daily Avg. for PG&E Citygate		$4.30	$3.95	$4.04	$3.86	$4.30	$4.34	$4.47	$4.16	$4.19				
NGI Bidweek for Malin		$4.26	$4.09	$3.35	$3.72	$3.55	$4.33	$4.06	$4.17	$3.81	$4.21			

Notes:

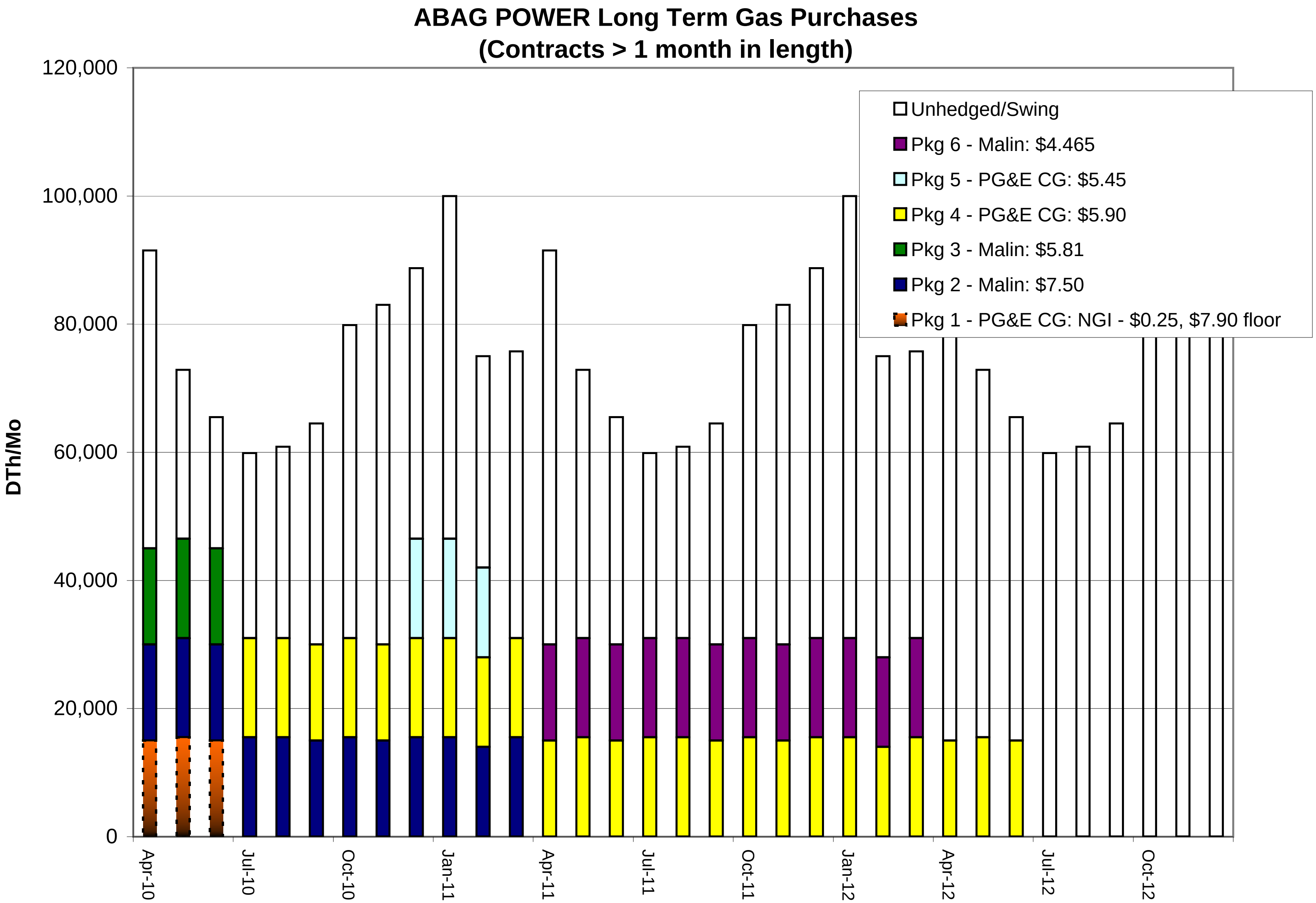
(1) All gas quantities in Dth and rates in $/Dth. (Does not include imbalance purchases traded to stroage.)
(2) WACOG at PG&E Citygate
(3) Includes costs to transport gas to PG&E Citygate from alternate delivery points, as well as physical storage costs.
(4) Includes scheduling fees, billing fees, administrative costs and misc. expenses; less interest income.
(5) PG&E charges billed to ABAG POWER via EDI process and passed through to customers. These costs do not necessarily tie directly to the actual gas usage shown above due to timing difference in reporting.
(6) From billing data
(7) Based on PG&E's G-NR1 rate schedule.
(8) Includes: Procurement Charge, Capacity Charge, Brokerage Fee, Shrinkage, and Storage.
(9) PG&E Transportation Charge; Customer Charge, and surcharge for Public Purpose Programs. Does not include Franchise Fees and City Taxes.

ATTACHMENT 5B



Gas Hedge Chart

ATTACHMENT 5C



Pacific Gas & Electric Company
2011 Gas Transmission & Storage Rate Case
A.09-09-013

Core Transport Agent (CTA) Settlement Agreement

August 20, 2010

A.09-09-013

CTA Settlement Agreement

August 20, 2010

Table of Contents

A.09-09-013
CTA Settlement Agreement

August 20, 2010

A) CTA Transmission and Storage Capacity Elections

1) These new procedures will become effective April 1, 2012. The CTA capacity structure as defined in this settlement will succeed the Gas Accord V Settlement unless changed by the CPUC in a future decision or settlement. No party to this settlement will petition for changes to these terms to be effective any time prior to April 2016, except as noted in A.9.

2) The provisions in this agreement apply to all long-term capacity held for the core customers by PG&E which the Commission approved. While these long-term capacity commitments may change in the future, PG&E's Core Gas Supply currently holds the following:
   - Gas Transmission Northwest - 609,968 Dth/day[1]
   - Foothills Pipe Line (BC System) - 611,054 Dth/day[1]
   - NOVA Gas Transmission - 619,369 Dth/day[1]
   - El Paso Natural Gas - 201,775 Dth/day
   - Transwestern Pipeline - 150,000 Dth/day
   - Ruby Pipeline - 250,000 Dth/day expected to start 11/1/2011
   - PG&E Firm Backbone Transmission as negotiated in the latest Gas Accord
   - PG&E Core Firm Storage as negotiated in the latest Gas Accord

3) CTAs will be given an annual election on long-term storage capacity (based on Winter Season gas usage) and a three-times-a-year election on long-term transmission capacity (based on the January Capacity Factor.)

4) Annual storage elections, for the upcoming April-March period, will be made each February. A mid-year storage true-up election will occur each August. Both of these storage elections will be done under procedures similar to that in the current G-CT tariff. CTAs will submit their storage capacity elections within ten (10) business days from the date PG&E initiates the election process.

5) CTA elections for pipeline capacity will be made on the following schedule:

Election Date	Election Period
Mid-January	March - June
Mid-May	July - October
Mid-September	November – February

   CTAs will submit their pipeline capacity elections within ten (10) business days from the date PG&E initiates the election process.

6) CTAs will be able to choose different election quantities for pipeline capacity for each month and for each pipeline segment. Capacity elected by a CTA will be assigned to the CTA for the period(s) elected. CTAs will be responsible for the billed costs of the pipeline capacity they elect to use (at

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[1] PG&E expects to reduce these contract quantities by approximately 250,000 Dth/day on 11/1/2011 with the start of the Ruby Pipeline contract.

the rate billed under the contract terms) and will be billed directly by the pipelines for those charges.

7) A three year transition period will be used to move to CTAs taking full cost responsibility for the capacity that is offered to them but is not elected. During the transition, PG&E's Core Portfolio will utilize, and take cost responsibility for, up to a set amount of the aggregate capacity rejected by all CTAs for each asset and for each month. The maximum aggregate amount (as a percentage of the total Core capacity holding) of the rejected capacity eligible for utilization by PG&E's Core Portfolio is shown in the table below:

Transition Time Period	Percentage
April 2012 to March 2013	12%
April 2013 to March 2014	7%
April 2014 to March 2015	4%

Any capacity rejected by the CTAs in aggregate in excess of these amounts will remain the aggregate cost responsibility of the CTAs. Examples of how the capacity costs will be allocated between the CTAs and PG&E's Core Portfolio are shown in Attachment A.

a) April 2015 onward is designated the Post-Transition Period, whereby CTAs will assume full cost responsibility in aggregate for all capacity not elected.

8) Except as detailed in A.7 for the capacity utilized by PG&E's Core Portfolio during the transition period, PG&E will manage the aggregate rejected capacity in the following manner: PG&E will release the rejected CTA capacity to the marketplace through auction, bulletin board listing, or similar process. CTAs understand that PG&E will have very little discretion in how this rejected capacity is resold, and therefore, CTAs agree not to protest the results of that process. The net cost (or benefit) of the rejected capacity, after including release revenue, will be applied to each CTA that rejected the capacity ratably by pipeline and month based on the amount of capacity rejected by the CTA on that pipeline. These charges (or credits) will be made directly to each CTA. An illustrative example of how these costs will be allocated between CTAs is shown in Attachment B.

9) One or more settlement parties may wish to file a petition or application seeking to modify Commission decisions setting storage and pipeline capacity holding levels for core customers on the PG&E system. Notwithstanding any other provision of this settlement, the parties agree that seeking such relief by a party, and granting such relief by the Commission, will not violate this settlement.

B) New Consumer Protection Rules

1) New rules will be developed in collaboration with the CTAs and the CPUC, but the CPUC's level of participation will be at its own discretion.

2) PG&E proposes to implement the new consumer protection rules, developed in collaboration with the CTAs and the CPUC, based on the following guiding principles, by no later than April 1, 2011:

   a) The new rules will be added to the Core Gas Aggregation Service Agreement and all applicable PG&E tariffs;

   b) The new rules will be submitted to the CPUC for approval through the Advice Filing process;

   c) CTAs agree not to oppose PG&E's advice filing of the consumer protection rules agreed upon in the collaborative effort;

   d) CTAs will provide PG&E with proof of a customer's authorized enrollment, within a specified timeframe, in response to customer complaints of unauthorized enrollments;

   e) The new rules will give CTAs the first opportunity to resolve a customer's complaint within a specified timeframe;

   f) The new rules will include monetary penalties assessed to CTAs if: 1) CTAs do not resolve complaints related to improper enrollments or provide proof of a customer's authorized enrollment within a specified timeframe; or 2) CTAs engage in fraudulent, deceptive, or abusive marketing activities;

   g) The new rules will allow PG&E to suspend CTAs from enrolling new customers for a specified timeframe, and allow PG&E to terminate a CTA's Core Gas Aggregation Service Agreement under specified conditions as agreed upon in the collaborative effort.

C) PG&E System Enhancements

1) PG&E agrees to implement the following system enhancements within the Gas Accord V period but no later than the date noted below:

   a) PG&E agrees to re-tune the Core Load Forecast model by October 1, 2011;

   b) PG&E proposes to evaluate the effectiveness of re-tuning the Core Load Forecast Model twelve months following its initial use, and in collaboration with the CTAs, determine whether a rebuild will be needed while incorporating the SmartMeter usage data by April 1, 2013;

   c) PG&E agrees to make the Preliminary Operating Imbalance data available to CTAs thirty days before the final Operating Imbalance Statement is issued by December 31, 2011;

   d) PG&E agrees to make CTA Operating Imbalance Adjustment File data available in an electronic format by October 31, 2012;

   e) PG&E agrees to implement an EDI 248 PG&E Consolidated Billing Report to replace the Daily Billing Reports currently sent to CTAs via e-mail within the Gas Accord V period;

f) PG&E agrees to make Gas Balancing Reports available online by April 1, 2013;

g) PG&E agrees to add a properly populated ESP Rate Code column to the Consolidated Billing Snapshot Report by April 1, 2013;

h) PG&E agrees to add the "Customer SA ID" data to the CTAs' payment report for CTAs utilizing PG&E Consolidated Billing by April 1, 2013.

D) Other CTA Issues

1) PG&E agrees to file a Summer distribution shrinkage rate and a Winter distribution shrinkage rate to reduce the monthly bias in the Core Load Forecast model.

2) PG&E agrees to consider CTAs' non-binding input regarding the adjustment factor for their specific load forecast prior to each month.

3) PG&E proposes to hold an annual meeting to address and receive feedback on CTA issues and concerns with the Core Gas Aggregation Program.

4) PG&E agrees to work through and adjust accounts manually if those accounts have a credit on the PG&E portion of the bill and a past due balance on the CTA portion to prevent inadvertent past due notices from being sent to the customer by PG&E.

5) PG&E agrees to provide the CTA Customer Snapshot Report by the 5th of each month, or the next business day if the 5th falls on a weekend or holiday.

6) PG&E agrees to provide the PG&E Consolidated Billing Snapshot Report by the 5th of each month, or the next business day if the 5th falls on a weekend or holiday.

7) PG&E will implement a change to the OFO exemption from $1,000 to 1,000 Dth per day per OFO occurrence.

8) PG&E agrees to implement a DASR Error Code rejection notification to CTAs who submit "Connect DASRs" with an incorrect customer rate code.

9) PG&E agrees to modify the Closing Bill collection process under PG&E Consolidated Billing to notify CTA customers when PG&E reverses any unpaid CTA charges to the CTA for collection.

10) PG&E agrees to make reasonable efforts to notify CTAs prior to activating a CTA customer for SmartMeter Interval Billing.

E) Complete Agreement

1) The CTA Settlement Agreement represents the complete agreement between PG&E and CTA Settlement Parties, and all parties acknowledge that PG&E no longer has an obligation to promote CTAs and the Core Gas Aggregation Program.

Attachment A

CTA Capacity Election Transition Period Hypothetical Examples

Example Parameters:

Total core contract for Pipe A: 100,000 Dth/day annual contract quantity
Pipeline allocations based on January Capacity Factor.

Example 1

Timeframe: Election made in mid-September 2012 for the month of November 2012
CTA Aggregate Market Share (based on January Capacity Factor): 15%

	Percentage of Total Core	Quantity Dth/day
Aggregate CTA market share / offering quantity	15%	15,000
Aggregate CTA acceptance quantity (assigned to and paid for by CTAs)	8%	8,000
Aggregate amount rejected by CTAs	7%	7,000
Rejected capacity utilized by PG&E Core Portfolio (maximum 12% in 1st year)	7%	7,000
Rejected capacity released/resold by PG&E (cost responsibility of CTAs)	0%	0

Example 2

Timeframe: Elections made in mid-May 2013 for the month of July 2013
CTA Aggregate Market Share (based on January Capacity Factor): 15%

	Percentage of Total Core	Quantity Dth/day
Aggregate CTA market share / offering quantity	15%	15,000
Aggregate CTA acceptance quantity (assigned to and paid for by CTAs)	2%	2,000
Aggregate amount rejected by CTAs	13%	13,000
Rejected capacity utilized by PG&E Core Portfolio (maximum 7% in 2nd year)	7%	7,000
Rejected capacity released/resold by PG&E (cost responsibility of CTAs)	6%	6,000

Example 3

Timeframe: Elections made in mid-January 2014 for month of May 2014
CTA Aggregate Market Share (based on January Capacity Factor): 9%

	Percentage of Total Core	Quantity Dth/day
Aggregate CTA market share / offering quantity	9%	9,000
Aggregate CTA acceptance quantity (assigned to and paid for by CTAs)	3%	3,000
Aggregate amount rejected by CTAs	6%	6,000
Rejected capacity utilized by PG&E Core Portfolio (maximum 4% in 3rd year)	4%	4,000
Rejected capacity released/resold by PG&E (cost responsibility of CTAs)	2%	2,000

Example 4

Timeframe: Elections made in mid-January 2015 for month of April 2015
CTA Aggregate Market Share (based on January Capacity Factor): 11%

	Percentage of Total Core	Quantity Dth/day
Aggregate CTA market share / offering quantity	11%	11,000
Aggregate CTA acceptance quantity (assigned to and paid for by CTAs)	8%	8,000
Aggregate amount rejected by CTAs	3%	3,000
Rejected capacity utilized by PG&E Core Portfolio (0% from April 2015 on)	N.A.	N.A.
Rejected capacity released/resold by PG&E (cost responsibility of CTAs)	3%	3,000

Attachment B

CTA Rejected Capacity Cost Allocation Hypothetical Example

Assumptions (Based on Example 2, Attachment A)	Cost ($)/Dth/Day	Percent	Dth/d
Month: July 2013			
Total Pipeline Contract Quantity:		100%	100,000
Daily Core Pipeline Reservation Rate	$0.15		
Total CTA Market Share and Capacity Offered:		15%	15,000
Aggregate CTA Acceptance:		2%	2,000
Aggregate CTA Rejection:		13%	13,000
Rejected capacity utilized by PG&E Core (max 7% in 2nd year):		7%	7,000
Rejected capacity released by PG&E (cost responsibility of CTAs):		6%	6,000
Assume 3 CTAs:			
CTA A has 1.5% market share, accepts all capacity offered		1.5%	
CTA B has 10.5% market share, rejects all capacity offered		10.5%	
CTA C has 3.0% market share, accepts a portion of capacity offered		3.0%	
Total CTA Market Share		15.0%	
Assume PG&E receives 75% of reservation rate for all capacity released to market			
Net cost responsibility (100%-75%) x $0.15/Dth/day	$0.0375		

Illustrative Example of Cost Allocation Methodology

	Offering		CTA Accepted Capacity		CTA Rejected Capacity				CTA Obligation			PG&E CP Obligation	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
CTAs	% Core Market Share	Quantity Offered / Allocation (Dth/d)	Quantity Accepted (Dth/d)	Charge by Pipeline to CTA ($/day)	Quantity Rejected (Dth/d)	% Share of Rejected Capacity (%)	Released Capacity Responsibility (Dth/d)	Cost Per Day ($/day)	Direct Charge by Pipeline ($/day)	Share of Rejected Capacity ($/day)	Total Cost Obligation ($/day)	Transition Utilization Quantity (Dth/day)	Allocation + Transition (Dth/day)
		(b*100,000)		(d*$0.15)		(f/sum of f)	(g*6,000)	(h*$0.0375)	(e)	(i)	(j+k)		(c+m)
CTA A	1.5%	1,500	1,500	225.00	0	0.00%	0.00	0.00	225.00	0.00	225.00		
CTA B	10.5%	10,500	0	0.00	10,500	80.77%	4,846.15	181.73	0.00	181.73	181.73		
CTA C	3.0%	3,000	500	75.00	2,500	19.23%	1,153.85	43.27	75.00	43.27	118.27		
PG&E CP	85.0%	85,000										7,000	92,000
	100.0%	100,000	2,000		13,000	100.00%	6,000.00						

The above calculation will be done individually for each month and each pipeline.

ABAG POWER
Operating Budget **Preliminary**
Fiscal Year Ending June 30, 2012

	Natural Gas		
	FY 2010-11 Approved (1)	**FY 2009-10 Projected**	**FY 2010-11 Proposed**
Revenues			
Sale of Energy	$ 9,307,278		$ 8,240,956
Interest Income - Banks/LAIF	30,000		30,000
Total revenues	9,337,278	-	8,270,956
Cost of energy			
Cost of Energy Used	6,136,453		5,078,949
PG&E Pass-Through Costs	2,761,186		2,761,909
Total cost of energy	8,897,639	-	7,840,858
Other Energy Costs			
Meter fees	-	-	-
Total Other Energy Costs	-	-	-
Program Expenses			
Billing Costs, external	10,200		10,200
Amortized Billing Software Costs	14,221		-
Scheduling agent fees	37,761		38,167
ABAG fees	354,456		364,731
Interest Expense/Bank Charges	18,000		12,000
Legal Expenses (outside)	5,000		5,000
Other Expenses	-		-
Total Program Expenses	439,638	-	430,098
Total expenses	9,337,278	-	8,270,956
True-up Adjustment	-	-	-
Core Annual Usage (Dths):	798,359		798,359
Noncore Annual Usage (Dths):	125,581		125,581
Core Gas Commodity ($/Dth):	$6.68		$5.53
Noncore Gas Commodity ($/Dth):	$6.37		$5.26
PG&E Pass-through ($/Dth):	$3.46		$3.46
Program Expenses (2) ($/Dth):	$0.44		$0.43
Core Total Rate ($/Dth):	$10.59		$9.43
Noncore Total Rate ($/Dth):	$6.82		$5.69

Notes:
(1) Approved budget June 2010
(2) Program expenses minus interest income.

ABAG POWER - Levelized Charges

Attachment 6B

Customer	Estimated Annual Usage	Gas Cost	Distribution Shrinkage	Storage Costs	PG&E Pass-through Costs (1)	Program Expenses (2)	Total Cost	FY2011-12 Monthly Levelized Charge	FY2010-11 Monthly Levelized Charge
						$400,098			
rate ($/th):		$0.525	3.0%	$0.013	$0.346	$0.043			
Core									
Alameda, City	204,755	$107,403	$3,222	$2,706	$70,834	$8,867	$193,032	$16,090	$18,070
Albany, City	10,716	$5,621	$169	$142	$3,707	$464	$10,103	$850	$950
Atherton, Town	6,430	$3,373	$101	$85	$2,224	$278	$6,062	$510	$570
Benicia, City	70,360	$36,907	$1,107	$930	$24,341	$3,047	$66,332	$5,530	$6,210
Contra Costa County GSD	1,471,305	$771,766	$23,153	$19,445	$508,995	$63,713	$1,387,072	$115,590	$129,800
Cupertino, City	55,839	$29,290	$879	$738	$19,318	$2,418	$52,643	$4,390	$4,930
Eastside Union H.S. District	94,166	$49,394	$1,482	$1,244	$32,576	$4,078	$88,775	$7,400	$8,310
Fremont, City	213,286	$111,878	$3,356	$2,819	$73,786	$9,236	$201,075	$16,760	$18,820
Gonzales, City	11,777	$6,178	$185	$156	$4,074	$510	$11,103	$930	$1,040
Golden Gate Bridge	79,745	$41,830	$1,255	$1,054	$27,587	$3,453	$75,179	$6,270	$7,040
Half Moon Bay, City	4,789	$2,512	$75	$63	$1,657	$207	$4,515	$380	$430
Hercules, City	40,709	$21,354	$641	$538	$14,083	$1,763	$38,379	$3,200	$3,600
Los Altos, City	30,542	$16,021	$481	$404	$10,566	$1,323	$28,793	$2,400	$2,700
Mill Valley, City	83,298	$43,694	$1,311	$1,101	$28,817	$3,607	$78,530	$6,550	$7,350
Millbrae, City									
Millbrae, City	34,747	$18,226	$547	$459	$12,021	$1,505	$32,757	$2,730	$3,070
Millbrae WWTP	104,455	$54,791	$1,644	$1,380	$36,136	$4,523	$98,475	$8,210	$9,220
Millbrae Total	139,201	$73,017	$2,191	$1,840	$48,156	$6,028	$131,232	$10,940	$12,290
Milpitas, City	172,168	$90,310	$2,709	$2,275	$59,561	$7,455	$162,311	$13,530	$15,190
Monte-Sereno, City	1,211	$635	$19	$16	$419	$52	$1,142	$100	$110
Moraga, Town	7,988	$4,190	$126	$106	$2,764	$346	$7,531	$630	$710
Napa County									
Napa County001	1,615	$847	$25	$21	$559	$70	$1,522	$130	$150
Napa County002	20,466	$10,736	$322	$270	$7,080	$886	$19,295	$1,610	$1,810
Napa County004	8,745	$4,587	$138	$116	$3,025	$379	$8,244	$690	$780
Napa County005	97,873	$51,339	$1,540	$1,293	$33,859	$4,238	$92,270	$7,690	$8,640
Napa County Total	128,699	$67,508	$2,025	$1,701	$44,523	$5,573	$121,331	$10,120	$11,380

ABAG POWER - Levelized Charges

Attachment 6B

Customer	Estimated Annual Usage	Gas Cost	Distribution Shrinkage	Storage Costs	PG&E Pass-through Costs (1)	Program Expenses (2)	Total Cost	FY2011-12 Monthly Levelized Charge	FY2010-11 Monthly Levelized Charge
						$400,098			
rate ($/th):		$0.525	3.0%	$0.013	$0.346	$0.043			
Oakland, City									
Oakland, City	752,338	$394,635	$11,839	$9,943	$260,270	$32,579	$709,266	$59,110	$66,370
Oakland Zoological	14,631	$7,675	$230	$193	$5,062	$634	$13,794	$1,150	$1,300
Oakland, City Total	766,969	$402,310	$12,069	$10,136	$265,331	$33,212	$723,060	$60,260	$67,670
Orinda, City	12,515	$6,564	$197	$165	$4,329	$542	$11,798	$990	$1,110
Pacifica, City	27,198	$14,266	$428	$359	$9,409	$1,178	$25,640	$2,140	$2,400
Petaluma, City	23,693	$12,428	$373	$313	$8,197	$1,026	$22,337	$1,870	$2,100
Pleasanton, City	179,245	$94,022	$2,821	$2,369	$62,010	$7,762	$168,984	$14,090	$15,820
Regional Admin. Facility	52,156	$27,358	$821	$689	$18,043	$2,259	$49,170	$4,100	$4,610
Richmond, City	232,402	$121,906	$3,657	$3,071	$80,399	$10,064	$219,097	$18,260	$20,510
Salinas, City	143,769	$75,413	$2,262	$1,900	$49,737	$6,226	$135,538	$11,300	$12,690
San Carlos, City	61,572	$32,297	$969	$814	$21,301	$2,666	$58,047	$4,840	$5,440
San Mateo County									
San Mateo County006	677,798	$355,536	$10,666	$8,958	$234,483	$29,351	$638,993	$53,250	$59,800
San Mateo County007	681,310	$357,378	$10,721	$9,004	$235,698	$29,503	$642,304	$53,530	$60,110
San Mateo County008	5,923	$3,107	$93	$78	$2,049	$256	$5,584	$470	$530
San Mateo County009	7,720	$4,050	$121	$102	$2,671	$334	$7,278	$610	$690
San Mateo County011	34,732	$18,218	$547	$459	$12,015	$1,504	$32,743	$2,730	$3,070
San Mateo County013	55,405	$29,063	$872	$732	$19,167	$2,399	$52,233	$4,360	$4,890
San Mateo County015	252,392	$132,391	$3,972	$3,336	$87,315	$10,929	$237,943	$19,830	$22,270
San Mateo County016	9,541	$5,005	$150	$126	$3,301	$413	$8,995	$750	$850
San Mateo County Total	1,724,821	$904,747	$27,142	$22,795	$596,699	$74,691	$1,626,074	$135,530	$152,210
San Rafael, City	67,991	$35,664	$1,070	$899	$23,521	$2,944	$64,098	$5,350	$6,000
Santa Clara County	955,169	$501,030	$15,031	$12,623	$330,439	$41,362	$900,485	$75,050	$84,260
Santa Rosa, City	275,909	$144,727	$4,342	$3,646	$95,450	$11,948	$260,113	$21,680	$24,340
Saratoga, City	14,027	$7,358	$221	$185	$4,853	$607	$13,224	$1,110	$1,240
Union City	21,536	$11,296	$339	$285	$7,450	$933	$20,303	$1,700	$1,900
Vallejo, City	415,508	$217,953	$6,539	$5,491	$143,744	$17,993	$391,720	$32,650	$36,660
Vallejo Sani.& Flood Control Dist	109,377	$57,373	$1,721	$1,446	$37,839	$4,736	$103,115	$8,600	$9,650
Watsonville, City	69,362	$36,383	$1,092	$917	$23,996	$3,004	$65,391	$5,450	$6,120
Winters, City	3,392	$1,779	$53	$45	$1,173	$147	$3,198	$270	$300

ABAG POWER - Levelized Charges

Attachment 6B

Customer	Estimated Annual Usage	Gas Cost	Distribution Shrinkage	Storage Costs	PG&E Pass-through Costs (1)	Program Expenses (2)	Total Cost	FY2011-12 Monthly Levelized Charge	FY2010-11 Monthly Levelized Charge
						$400,098			
rate ($/th):		$0.525	3.0%	$0.013	$0.346	$0.043			
TOTAL - Core	7,983,594	$4,187,759	$125,633	$105,511	$2,761,909	$345,717	$7,526,529	$627,410	$704,530
Rate ($/th)		$0.525	$0.016	$0.013	$0.346	$0.043	$0.943		
	Total ABAG POWER Commodity Cost - Core:			$0.553					
	Member Rate - Core:			$0.597					
Non-Core			0.2%						
Contra Costa, County	0	$0	$0			$0	$0	$0	$0
San Mateo County	249,607	$130,930	$262			$10,809	$142,001	$11,840	$14,180
Santa Rosa, City (Co-gen)	818,249	$429,209	$858			$35,433	$465,501	$38,800	$46,490
Watsonville, City (Co-gen)	187,951	$98,589	$197			$8,139	$106,925	$8,920	$10,680
TOTAL - Non-core	1,255,808	$658,728	$1,317	$0	$0	$54,381	$714,427	$59,560	$71,350
Rate ($/th)		$0.525	$0.001	$0.000	$0.000	$0.043	$0.569		
	Total ABAG POWER Commodity Cost - Non-core:			$0.526					
	Member Rate - Non-core:			$0.569					
GRAND TOTAL (Core + Non-core)	9,239,402	$4,846,488	$126,950	$105,511	$2,761,909	$400,098	$8,240,956	$686,970	$775,880
							% Change:	-11.5%	
							Working Capital Deposits:	$ 2,020,437	
							Months:	2.94	

Notes:

(1) Includes estimates for: Customer Charge, Transportation Charge, Public Purpose Programs surcharge, and franchise fee.

(2) Program expenses less interest income.