ASSOCIATION OF BAY AREA GOVERNMENTS
Representing City and County Governments of the San Francisco Bay Area

ABAG POWER
ANNUAL BOARD MEETING

October 24, 2013 (10:30 a.m. to 1:00 p.m.)

Association of Bay Area Governments
Joseph P. Bort MetroCenter Auditorium
101 Eighth Street, Oakland, CA 94607

Chairman: Richard Sealana

1.	**Welcome** ATTACHMENT A - ABAG POWER JPA MEMBER LIST	Sealana	
2.	**Public Comments**	Sealana	
3.	**Approval of Minutes from October 25, 2012 Annual Board Meeting** ATTACHMENT 3A – SUMMARY MINUTES OF OCTOBER 25, 2012	Sealana	**Action**
4.	**Election of ABAG POWER Officers (Chair and Vice Chair)** ATTACHMENT 4A - PROPOSED EXECUTIVE COMMITTEE FOR FY 13-14	Sealana	**Action**
5.	**Staff Report and Review of Natural Gas Program** Staff will report the results of the Natural Gas Program for the 2012 – 2013 fiscal year, as well as provide multi-year review of the Program. ATTACHMENT 5A - STAFF REPORT ON NATURAL GAS PROGRAM ATTACHMENT 5B - SUMMARY OF NATURAL GAS PROGRAM FY2012-13	Lahr	Info.
6.	**Financial Review** Staff will review preliminary Financial Statements for FY 2012-13 ATTACHMENT 6A – FINANCIAL REPORTS MEMO ATTACHMENT 6B.1 – BALANCE SHEET ATTACHMENT 6B.2 – INCOME STATEMENT	Pike	Info.
7.	**Natural Gas Pipeline Capacity Issue** Staff will discuss the effects to the program of the recent stranded pipeline capacity costs. ATTACHMENT 7A – MEMO RE: PIPELINE CAPACITY STRANDED COSTS	Lahr Sealana	Info.
	Break for Lunch		
8.	**Guest Speaker – Bay Area Regional Energy Network (BayREN)** BayREN Program Manager (Jenny Berg) and subprogram leads will summarize the programs and accomplishments to date. • Single Family Residential/Financing (Demetra McBride) • Multi-family Residential (Heather Larson) • Codes & Standards (Daniel Hamilton)	Berg McBride Larson Hamilton	Info.

Adjourn approximately 1:00 p.m.

THE BOARD MAY TAKE ANY ACTION, INCLUDING NO ACTION, ON ANY ITEM ON THIS AGENDA.

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Joseph P. Bort MetroCenter 101 Eighth Street Oakland, California 94607-4756

ABAG POWER Board of Directors (JPA Membership)

Total JPA Membership = 67
Current Gas Members = 38

Jurisdiction	Primary & Alternate	Membership Status
Alameda, City of	Brad Farmer (P)	Current Gas Member
Albany, City of	Aaron Walker (A)	Current Gas Member
Benicia, City of	Brenda Olwin (P) Brad Kilger (A)	Current Gas Member
Cupertino, City of	Carol Atwood (P) Erin Cooke (A)	Current Gas Member
Fremont, City of	Mike Sung (P) Dan Schoenholz	Current Gas Member
Gonzales, City of	Rene Mendez (P) Carlos Lopez (A)	Current Gas Member
Half Moon Bay, City of	Laura Snideman (P) Jan Cooke (A)	Current Gas Member
Hercules, City of	Vacant (P) Steve Duran (A)	Current Gas Member
Housing Authority of the City of Alameda	Alan Olds (P) Robert Haun (A)	Current Gas Member
Los Altos, City of	Dave Brees (P) Doug Schmitz (A)	Current Gas Member
Mill Valley, City of	Eric Erickson (P)	Current Gas Member
Millbrae, City of	Khee Lim (P)	Current Gas Member
Milpitas, City of	Emma Karlen (P) Chris Schroeder (A)	Current Gas Member
Monte Sereno, City of	Brian Loventhal (P)	Current Gas Member
Oakland, City of Oakland Zoo	Scott Wentworth (P) Justin J. Hurd	Current Gas Member
Orinda, City of	Janet Keeter (P) Tonya Gilmore (A)	Current Gas Member
Pacifica, City of	Jim Reese Sandra McClellan (A)	Current Gas Member
Petaluma, City of	Bill Mushallo (P)	Current Gas Member
Pleasanton, City of	Daniel Smith (P)	Current Gas Member
Richmond, City of	Angela Walton (P) Adam Lenz (A)	Current Gas Member

Jurisdiction	Primary & Alternate	Membership Status
Salinas, City of	Michael Ricker (P) Miguel Gutierrez (A)	Current Gas Member
San Carlos, City of	Jay Walter (P) Rebecca Mendenhall (A)	Current Gas Member
San Rafael, City of	Nader Mansourian (P) Richard Landis (A)	Current Gas Member
Santa Rosa, City of	Mark Armstrong (P) Ed Buonaccorsi (A)	Current Gas Member
Saratoga, City of	Thomas Scott (P) Mary Furey (A)	Current Gas Member
Union City, City of	Richard Sealana (P)	Current Gas Member
Vallejo, City of	Fiona Strykers (A)	Current Gas Member
Watsonville, City of	Gabriel Gordo (P)	Current Gas Member
Winters, City of	John Donlevy (P) Shelly Gunby (A)	Current Gas Member
Atherton, Town of	George Rodericks (P)	Current Gas Member
Moraga, Town of	Stephanie Hom (P) Edric Kwan (interested party)	Current Gas Member
Contra Costa, County of	Julie Bueren (P) Steve Kowalewski (A)	Current Gas Member
Napa, County of	Steve Lederer (P) Jason Campbell (A)	Current Gas Member
San Mateo, County of	Doug Koenig (P) Gary Behrens (A)	Current Gas Member
Santa Clara, County of	Lin Ortega (P) Jeff Draper (A)	Current Gas Member
Golden Gate Bridge District	Jennifer Mennucci (P) Alice Ng (A)	Current Gas Member
R.A.F.C.	Mamie Lai (P) Robert Hoffman (A)	Current Gas Member
Vallejo Sanitation & Flood Ctrl.	Ron Matheson (P)	Current Gas Member
JPA Members (non-active, ex-electric and/or gas opt-out members)		
Antioch, City of	Dawn Merchant (P) Jim Jakel (A)	Non-Active
Arcata, City of	Randy Mendosa (P)	Non-Active
Belmont, City of	Greg Scoles (P)	Non-Active

Jurisdiction	Primary & Alternate	Membership Status
Berkeley, City of	Neal De Snoo (P)	Non-Active
Cloverdale, City of	Nina D. Regor (P)	Non-Active
Cotati, City of	Dianne Thompson (P)	Non-Active
Daly City, City of	Vacant	Non-Active
Davis, City of	Vacant	Non-Active
El Cerrito, City of	Maria Sanders (P) Garth Schultz (A)	Non-Active
Foster City, City of	Vacant	Non-Active
Menlo Park, City of	Vacant	Non-Active
Newark, City of	Peggy Claassen (P)	Non-Active
Patterson, City of	City Clerk	Non-Active
Pinole, City of	Belinda Espinosa (P)	Non-Active
San Leandro, City of	Lianne Marshall (P)	Non-Active
San Mateo, City of	David Culter (P)	Non-Active
San Pablo, City of	Bradley J. Ward (P) Brock Arner (A)	Non-Active
Sebastopol, City of	Ron Puccineli (P)	Non-Active
Hillsborough, Town of	Edna Masbad (P)	Non-Active
Los Altos Hills, Town of	Carl Cahill (P)	Non-Active
Butte, County of	Grant Hunsicker (A)	Non-Active
Monterey, County of	Mario Salazar (P)	Non-Active
Sonoma, County of	John Haig (P)	Non-Active
Windsor, Town of	James McAdler (P)	Non-Active
H.A.R.D.	Larry Lepore (P) Karl Zabel (A)	Non-Active

Jurisdiction	Primary & Alternate	Membership Status
Housing Authority County of Alameda	Tom Makin (P) Christine Gouig (A)	Non-Active
Los Trancos County Water Dst.	Keri Tate (P)	Non-Active
South County Fire Authority	Vacant (P)	Non-Active
West County Wastewater District	Brian Hill (P)	Non-Active

SUMMARY MINUTES

ABAG POWER Annual Board of Directors' Meeting 2012
October 25, 2012
Joseph P Bort MetroCenter
101 Eighth Street, Oakland, CA 94607-4756

WELCOME
Chairman Chris Schroeder opened the meeting of the ABAG POWER Board of Directors' with introductions at 10:30 a.m.

The agencies having a representative at this meeting were as follows:

Jurisdictions Represented	**Representatives**
City of Albany	Aaron Walker
City of Benicia	Karan Reid
City of Fremont	Harriet Commons
City of Los Altos	Dave Brees
City of Millbrae	Ron Popp
City of Milpitas	Chris Schroeder
City of Oakland	Scott Wentworth
City of Orinda	Janet Schneider
City of Petaluma	Steve Simmons
City of Pleasanton	Laura Ryan
City of Richmond	Adam Lenz
City of San Carlos	Jay Walter
City of San Rafael	Richard Landis
City of Santa Rosa	Mark Armstrong
City of Saratoga	Thomas Scott
City of Union City	Richard Sealana
City of Watsonville	Gabe Gordo
County of Contra Costa	Julie Bueren/Terry Mann
County of Napa	Carlos Solorio
County of San Mateo	Doeg Koenig
County of Santa Clara	Brad Vance
Golden Gate Bridge & Highway District	Jennifer Mennucci
Housing Authority for the City of Alameda	Robert Haun
RAFC	Mamie Lai
Others Present	
City of Newark	Lanka Diaz/Peggy Claassen
Rafael Reyes	Bay Area Climate Collaborative
Jenne Andrews (attended briefly towards the end)	City of Oakland
Mahasin Abdul Salaam (did not attend the meeting)	Member of the Public

Staff:

Herbert Pike	ABAG
Jerry Lahr	ABAG POWER
Vina Maharaj	ABAG POWER
Kenneth Moy	ABAG

WELCOME & CHAIRMAN'S OPENING REMARKS

Chairman Schroeder welcomed the board members and provided a brief history and a general overview of the ABAG POWER Program. He introduced and extended a special acknowledgment to the 2011-12 Executive Committee and the ABAG POWER Staff.

PUBLIC COMMENTS

There were no public comments.

APPROVAL OF SUMMARY MINUTES OF OCTOBER 27, 2011 ANNUAL BOARD MEETING

Motion was made by Popp/S/Sealana/24:0:0/C/ to approve the Summary Minutes of October 27, 2011 ABAG POWER Annual Board of Directors' meeting.

ELECTION OF CHAIR AND VICE CHAIR FOR PROGRAM YEAR 2012-13

Motion was made by Popp/S/Ryan/24:0:0/C/ to elect Richard Sealana of the City of Union City as Chairman and Mark Armstrong as Vice-Chairman of the ABAG POWER Executive Committee for program year 2012-13.

RATIFICATION OF ABAG POWER EXECUTIVE COMMITTEE FOR PROGRAM YEAR 2012-13

Motion was made by Popp/S/Armstrong/24:0:0/C/to approve the proposed ABAG POWER Executive Committee for program year 2012-2013 as follows:

Mark Armstrong, City of Santa Rosa
Julie Bueren, County of Contra Costa
Angela Walton, City of Richmond
Laura Ryan, City of Pleasanton
Chris Schroeder, City of Milpitas
Richard Sealana, City of Union City

STAFF REPORT AND REVIEW OF NATURAL GAS PROGRAM

Lahr provided an in-depth report on the operations of the Natural Gas Program for FY2011-12. He provided a review of the program and discussed the program goals, long-term program achievements and gas purchasing strategies.

ABAG POWER's blend of long-term and short-term gas purchases resulted in a weighted average cost of gas for the year of $4.06/Dth, representing a decrease of approximately 20% over the prior year. ABAG POWER's annual weighted average price was approximately 1.7% lower than PG&E's similar total rate (GNR-1). Due to the Program's levelized billing structure and long-term purchasing strategy, ABAG POWER's monthly rates were more stable than PG&E's rates throughout the year.

FINANCIAL REVIEW
Herbert Pike presented the preliminary financial reports for fiscal year ending June 30, 2012. Auditors were in the process of auditing the financial statements, which will be available by December, 2012.

UPDATE ON OTHER ENERGY PROGRAMS
Lahr provided a status update on various energy efficiency and sustainability programs being undertaken by ABAG. There was discussion about ABAG's proposal to implement a Bay Area Regional Energy Network.

GUEST SPEAKER – Rafael Reyes – Climate Collaborative Executive Director
Rafael Reyes spoke about recent Electric Vehicle activities and planning in the Bay Area.

ADJOURNMENT
Chairman Schroeder adjourned the meeting at 1:00 p.m.

/vm

*Example of a motion – *[Member No. 1/S/Member No. 2/O/Member No. 3/roll call vote/C/8:0:0]* means Member No.1 motions, seconded by Member No.2, Opposed by Member No. 3, after roll call vote, motion carries, 8 = "yes" votes, 0 = "no" votes and 0 = abstentions.

Proposed Executive Committee for FY 2013 – 2014

- Julie Bueren, Director of Public Works
  County of Contra Costa

- Stephanie Hom, Administrative Services Director
  City of Orinda

- Alan Olds, Finance Director
  Housing Authority of the City of Alameda

- Chris Schroeder, Purchasing Officer
  City of Milpitas

- Richard Sealana, Superintendent of Public Works
  City of Union City

- Daniel Smith, Director Operation Services
  City of Pleasanton

- Angela Walton, Public Works Operations Administrator
  City of Richmond

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MEMORANDUM

ASSOCIATION OF BAY AREA GOVERNMENTS

Representing City and County Governments of the San Francisco Bay Area **Agenda Item 5A**

DATE: October 17, 2013

TO: ABAG POWER Board of Directors

FROM: Gerald L. Lahr, Manager, ABAG POWER

RE: **Staff Report on 2012-2013 Natural Gas Program**

Summary

Natural gas prices began a modest climb during the past year which was a turn around from the decline that the market has seen over the previous three years. Near-term, market-rate prices rose for most of the year – beginning at about \$3.00/dth and increasing to approximately \$4.20/Dth in April-May. Recently prices have come down to approximately \$4.00/Dth. While the direction of prices seems to have reversed, the overall the market volatility remains consistent with the recent past.

During the year, ABAG POWER purchased 43% of its gas with forward gas supply contracts, while additional amounts were purchased on the short-term market. The Program's gas costs ranged from a high of \$4.24/Dth as part of a long-term contract, to a low of \$2.97/Dth purchased on the spot market. ABAG POWER's blend of long-term and short-term gas purchases resulted in a weighted average cost of gas for the year of \$3.70/Dth, representing a decrease of approximately 9% over the prior year. Ultimately, ABAG POWER's annual weighted average price was approximately 1.4% lower than PG&E's similar total rate (GNR-1). Due to the Program's levelized billing structure and long-term purchasing strategy, ABAG POWER's monthly rates were more stable than PG&E's rates throughout the year.

Program Goals

Since 2002 the ABAG POWER Natural Gas Program has operated with the dual, and often competing, goals of *Cost Savings* and *Price Stability*.

- **Price Stability.** It is desirable that the Program's purchasing strategy and costs allocation methods be such that will provide members a reasonable degree of certainty of the costs to be shared within any given program year.
- **Cost Savings.** Given the desire for price stability, the Program shall attempt to provide gas procurement services for less than the equivalent services provided by the default provider (i.e. PG&E).

To meet these goals the program has implemented a gas purchasing strategy that emphasizes multiple layers of long-term, fixed-price contracts for a majority of its gas load, while the remaining portion of gas is purchased with short-term, indexed-based contracts. This strategy has generally resulted in positive savings during times of rising markets, and negative savings during falling markets, while maintaining price stability.

The general gas purchasing strategy established by the Executive Committee is as follows:

- Purchase up to three-year, fixed-price contract(s) for up to 40% of the current gas requirements.
- Purchase up to one-year, fixed-price contracts for up to 30% of the current gas requirements.
- Purchase the remaining gas requirements based on a monthly or daily index that will float with the market price of gas.

During the past year ABAG POWER continued to purchase a majority of its gas in the shorter term market in order to take advantage of lower spot prices, and also locked in a couple of longer term contracts to gain future stability while the market is at a relative low.

Fiscal Year 2012 – 13.

During the recently completed fiscal year, ABAG POWER purchased 43% of its gas with forward gas supply contracts.[1] The remaining gas requirements were purchased in monthly or daily blocks with the price tied to a market index.[2] The Program's gas costs ranged from a high of $4.24/Dth for gas tied to a long term contract, to a low of $2.97/Dth for daily gas in August 2012.[3] The Natural Gas Program's net savings for the year ending June 30, 2011 was 1.4%.

The program's total monthly levelized rate (gas commodity and distribution) remained static throughout the year, as compared PG&E's similar (GNR-1) rate which ranged from $3.92 – 5.30/Dth.

Long Term Program Metrics.

ABAG POWER's average annual savings for the period July 2003 to June 2013 was 0.7% [4] (does not include proceeds from 2009 gas litigation settlement: $557,000). Throughout this period the Program's prices continued to be more stable than PG&E's. This is due to a strategy that relies more heavily on longer-term, fixed-price purchases, as well as the levelized billing system.

While ABAG POWER's fixed price contracts produce greater stability, and have avoided the significant price spikes seen over the past several years, at times these contract prices are above the monthly and daily indices that are primarily followed by PG&E.

[1] Contracts greater than one month in length. Purchases staged throughout the year.
[2] National Gas Intelligence's (NGI's) monthly Bidweek index, or the Gas Daily's daily index for the appropriate delivery point.
[3] Gas priced at PG&E Citygate.
[4] Compared to PG&E's GNR-1 rate.

Operations and Billing.

Scheduling. During the past year ABAG POWER issued an RFP for gas scheduling and balancing services, and DMJ Gas Marketing was selected as the new gas scheduling agent. DMJ began providing scheduling services as of July 2013.

The program continues to schedule deliveries to take advantage of the transportation capacity that PG&E allocates to the program, when possible. However, as discussed last year, due to regulatory changes implemented in April 2012, the rules regarding the allocation of PG&E's pipeline capacity holdings have changed, and this has resulted in additional costs to the program. Several Core Transportation Agents (CTAs) have joined forces to petition the California Public Utilities Commission (CPUC) to revise these regulations so that programs such as ABAG POWER's are not burdened with stranded costs as a result of PG&E's pipeline capacity contracts. (See separate memo for additional information.)

Gas Purchase Agreements. ABAG POWER continues to seek out gas suppliers that may provide benefits to its portfolio. The program currently maintains master gas purchase contracts with the following suppliers:

- Allied Energy Resources
- BP Energy
- Cook Inlet Energy Supply
- Shell Energy North America (formerly Coral Energy)
- Occidental Energy Marketing, Inc. (subsidiary of Occidental Petroleum)
- Pacific Summit Energy (subsidiary of Sumitomo Corp.)
- Sierra Southwest (Touchstone Energy Cooperative)
- United Energy Trading (UET)
- Utility Resource Solutions (Spark Energy)

Noncore. The ABAG POWER natural gas pool includes three large-usage (noncore) accounts. Natural gas for these accounts is scheduled separately, although it is allocated from the same pooled purchases.

Storage. Core aggregation programs such as ABAG POWER are required to maintain certain gas storage requirements throughout the year. For example, ABAG POWER is currently required to have approximately 750,000 therms of gas in storage at the start of the winter period (Nov. 1st). During the previous storage cycle,[5] ABAG POWER chose to contract with a third-party storage facility (Wild Goose Storage) for a majority of its storage requirement (80%) in order to save costs, while continuing to utilize PG&E's storage facilities for a minority of its storage requirement (20%) to retain operational flexibility. However, due to the recent regulatory changes that require ABAG POWER to pay for a portion of PG&E storage regardless of whether or not it is actually used, the

[5] Annual Storage Cycle: April - March

program has decided to use PG&E storage for 100% of its requirement in order to reduce stranded capacity costs.

Billing. ABAG POWER continues to provide "ESP Consolidated Billing" services for all core accounts utilizing Electronic Data Interchange (EDI) processing. Under this option members receive only one bill with both ABAG POWER and PG&E charges. EDI processing is not available for noncore accounts, so these are billed using the "Dual Billing" option. Under Dual Billing PG&E sends a separate bill with just transportation and miscellaneous charges (i.e. no commodity charge).

ABAG POWER maintains its own internal accounting system that provides for "levelized" billing. Every member is invoiced each month for an amount that represents 1/12th of the annual cost estimate for that member. Along with the monthly levelized invoice, the program sends each member a detailed report showing the actual usage for each account. After the end of the fiscal year the actual costs for each member are compared to the levelized billings, and a credit or charge is then applied to true-up any difference.

Financial

The total cost of the natural gas program for 2012-2013 decreased from the previous fiscal year by 7%: from $6.9 million to $6.4 million. This was primarily the result of a decrease in the Program's total gas commodity expense. Contributing to this decrease was a reduction in gas consumption of 5.5%. A review of each major program cost element is summarized below:

Natural Gas Commodity Cost. The natural gas commodity cost decreased from $3.8 million in 2011-12 to $3.4 million for the 2012-2013 program year. This total was below the originally budgeted amount of $3.7 million, and was the primary reason for the decrease in total program gas cost. Total gas consumption decreased from 9,094,530 to 8,590,230 therms (5.5%) contributing to this reduction.

The commodity portion of program costs is composed of: (1) natural gas purchases from gas suppliers for monthly consumption, (2) shrinkage, (3) required storage, and (4) additional costs to transport the gas to PG&E's distribution system. The natural gas commodity costs represented 53% of the total program costs for the year

PG&E Pass-through Costs.[6] A major cost of the natural gas program is the amount charged by PG&E for the distribution of natural gas to customers as well as other public benefit charges. These costs are charged by PG&E to all customers and are subject to regulation by the CPUC. During the past fiscal year these costs totaled approximately $2.7 million representing a 3.5% decrease from the prior year due to a decrease in gas consumption.[7] The relative impact of the PG&E passthrough costs was 41% of total program costs.

[6] PG&E costs for noncore accounts are paid by the agency directly to PG&E, and are therefore not included in ABAG POWER's financial reports.
[7] Unit rate PG&E pass-through costs increased from an average of $0.304 to $0.351/therm.

Agenda Item 5A

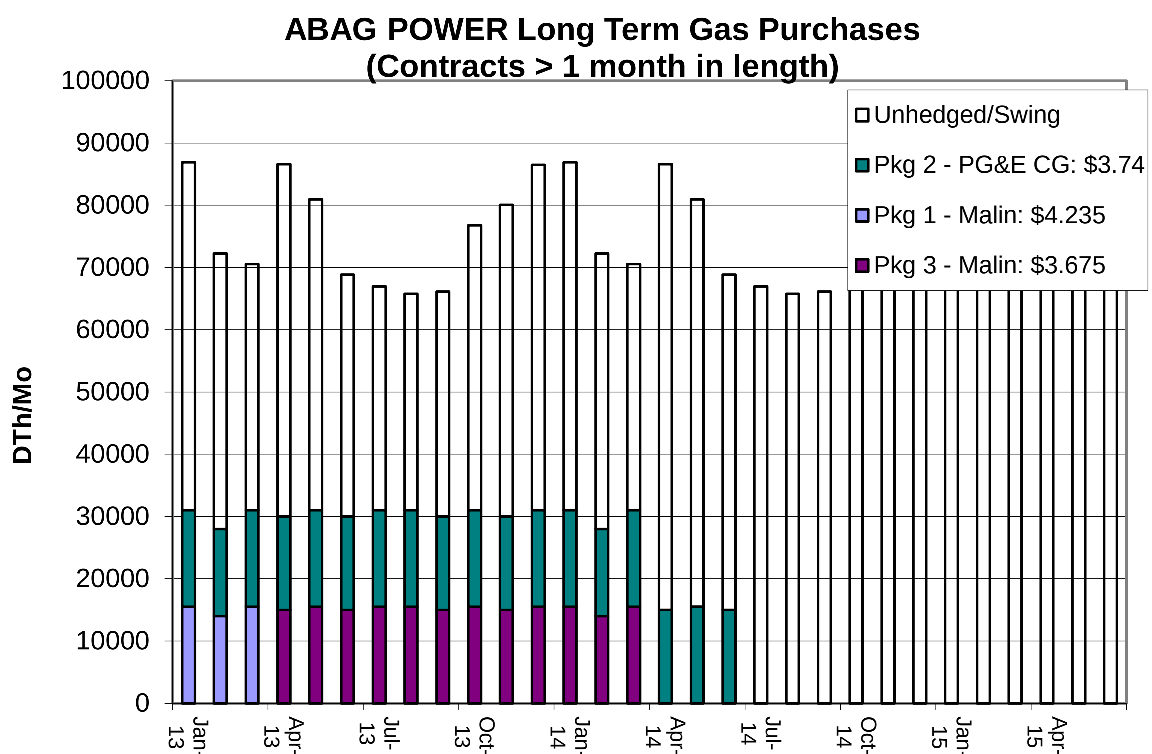
Program Expenses. The remaining costs of the program are the expenses for program management, billing services, gas scheduling and administrative support, including financial and legal services. The cost of these services was approximately $375,792 or about 6% of the total program cost.

Working Capital Deposits. The ABAG POWER natural gas program agreement requires that each new member of the program provide a deposit equal to two times their estimated monthly charges (Working Capital Deposit). These funds are kept on deposit, and are refunded to members if they leave the program. The total deposit amount is generally reviewed on an annual basis to ensure the program has adequate cash reserves to meet all its payment obligations.

As of June 30, 2013 the gas program had total Working Capital Deposits of: $2,000,785 which represents 3.1 months' worth of currently budgeted expenditures. This is deemed sufficient, and as a result, additional working capital deposits are not anticipated during the current year.

Conclusion

The goals of ABAG POWER's Natural Gas Program are to provide natural gas at a rate competitive with, or less than, the default provider (i.e. PG&E), while at the same time providing a rate that is stable and predictable. These goals require a balance between the need to have a large percentage of gas in long-range, fixed-price contracts or other hedge instrument, and the desire not to lock the program into higher than market rates. ABAG POWER currently maintains a hedged position of approximately 35% for FY 2013-14 (see chart below).



During the coming year we will continue to evaluate the Program's gas purchasing strategy to best maximize the goals of the Program: *Cost Savings* and *Price Stability*. ABAG POWER will also be looking for opportunities to aid members in all areas of energy management such as the recently initiated *San Francisco Bay Area Regional Energy Network* (BayREN).

We look forward to working with you during the coming year to make this program responsive to the needs of its member agencies.

/vm

ABAG POWER Natural Gas Program

FY 2012-13 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	15,500	14,000	15,500	15,000	15,500	15,000	182,500
	Price	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$3.68	$3.68	$3.68	
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	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	$3.74	
Purchase 3	Qty	24,800	24,800	24,000	24,800	15,000	24,242	24,242	21,896	23,839	23,070	23,839	23,070	277,598
	Price	$2.50	$2.90	$2.57	$2.91	$3.96	$3.73	$3.43	$3.40	$3.41	$3.86	$3.95	$4.02	
Purchase 4	Qty	2,150	7,275	13,075	15,600	23,460	28,000	37,000	23,500	17,750	19,700	16,250	6,750	210,510
	Price	$3.11	$2.97	$3.39	$3.97	$3.54	$3.74	$3.65	$3.65	$4.01	$4.20	$4.17	$3.97	
Purchase 5	Qty					2,000								2,000
	Price					$3.87								
Total Quantity Purchased		57,950	63,075	67,075	71,400	70,460	83,242	92,242	73,396	72,589	72,770	71,089	59,820	855,108
Total Purchase Cost		$192,289	$217,173	$225,581	$257,674	$269,816	$318,763	$341,687	$271,756	$276,157	$283,100	$276,805	$230,736	$3,161,537
Backbone Shrinkage (Dths)		(403)	(403)	(390)	(403)	(390)	(403)	(403)	(364)	(403)	(390)	(403)	(390)	
WACOG[2]		$3.34	$3.47	$3.38	$3.63	$3.85	$3.85	$3.72	$3.72	$3.83	$3.91	$3.92	$3.88	$3.70
Storage/Inventory														
Total Injections/ (Withdrawals)		9,751	9,300	9,000	9,218	(1,618)	(17,500)	(15,500)	(11,675)	(17,825)	9,000	7,113	8,800	(1,936)
Total Inventory Quantity (Dths)		51,600	60,900	69,900	79,118	77,500	60,000	44,500	32,825	15,000	24,000	31,113	39,913	
Total Inventory ($)		$211,619	$243,843	$274,290	$307,742	$302,094	$241,001	$186,891	$146,134	$83,895	$118,329	$146,147	$180,608	
Avg. Inventory Rate ($/Dth)		$4.10	$4.00	$3.92	$3.89	$3.90	$4.02	$4.20	$4.45	$5.59	$4.93	$4.70	$4.53	
Gas Program Monthly Expenses (from Financial Reports)														
Cost of Energy Used[3]		$ 178,693	$ 203,938	$ 214,356	$ 243,575	$ 290,999	$ 399,116	$ 414,907	$ 331,469	$ 358,460	$ 277,588	$ 278,234	$ 190,643	$ 3,381,978
Program Operating Expenses[4]		23,023	32,315	30,203	41,748	30,692	23,852	20,609	31,043	29,548	36,429	36,522	40,789	376,774
Subtotal		$ 201,716	$ 236,253	$ 244,559	$ 285,323	$ 321,690	$ 422,967	$ 435,516	$ 362,512	$ 388,009	$ 314,018	$ 314,756	$ 231,432	$ 3,758,751
Rate ($/Dth)		$3.46	$4.26	$4.07	$4.59	$4.53	$4.17	$3.89	$3.99	$4.87	$5.18	$5.59	$4.55	$4.38
PG&E Pass-through costs[5]		141,719	168,739	146,220	153,910	213,438	255,305	463,637	267,851	304,847	214,564	160,854	175,037	2,666,120
Total ABAG POWER Cost		$ 343,434	$ 404,992	$ 390,779	$ 439,233	$ 535,128	$ 678,272	$ 899,154	$ 630,363	$ 692,856	$ 528,581	$ 475,610	$ 406,469	$ 6,424,872
Actual (metered) Gas Usage														
Core[6]		48,407	45,020	48,871	52,749	62,829	91,349	102,861	81,610	73,841	55,616	50,352	45,204	758,707
Non Core		9,884	10,448	11,282	9,461	8,251	9,961	9,067	9,331	5,895	5,061	5,992	5,684	100,316
Total Program Usage		58,291	55,468	60,152	62,210	71,080	101,310	111,928	90,940	79,735	60,677	56,343	50,888	859,023
ABAG POWER Total Core Rate		$ 6.39	$ 8.01	$ 7.06	$ 7.50	$ 7.92	$ 6.97	$ 8.40	$ 7.27	$ 8.99	$ 9.03	$ 8.78	$ 8.42	
PG&E Rate[7]														
Procurement Charge[8]		4.58	4.34	3.92	4.00	4.98	4.49	4.29	4.70	4.06	4.71	5.30	4.76	
Transportation/Other Charge[9]		2.93	3.75	2.99	2.92	3.40	2.79	4.51	3.28	4.13	3.86	3.19	3.87	
Total PG&E Rate		$ 7.51	$ 8.09	$ 6.91	$ 6.91	$ 8.38	$ 7.28	$ 8.80	$ 7.98	$ 8.19	$ 8.57	$ 8.49	$ 8.63	

ABAG POWER Natural Gas Program

FY 2012-13 Monthly Summary of Operations

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Rate Comparison													
Monthly Rate Difference ($/Dth)	(1.12)	(0.08)	0.15	0.59	(0.46)	(0.31)	(0.40)	(0.71)	0.81	0.47	0.29	(0.21)	
Monthly Savings ($)	54,408	3,762	(7,142)	(31,083)	28,727	28,749	41,243	57,905	(59,782)	(25,913)	(14,576)	9,438	
Cumulative 'Savings' ($)	54,408	58,170	51,028	19,944	48,672	77,421	118,664	176,569	116,786	90,874	76,298	85,737	
Cumulative 'Savings' (%)	15.0%	8.0%	4.8%	1.4%	2.5%	3.0%	3.4%	4.2%	2.4%	1.7%	1.3%	1.4%	
Monthly Index Postings													
NGI Bidweek for PG&E Citygate	$3.00	$3.11	$2.90	$3.45	$3.89	$4.08	$3.72	$3.66	$3.72	$4.22	$4.25	$4.27	
Gas Daily Avg. for PG&E Citygate	$3.01	$3.03	$3.30	$3.95	$3.83	$3.77	$3.67	$3.63	$4.04	$4.19	$4.15	$3.92	
NGI Bidweek for Malin	$2.49	$2.89	$2.56	$2.90	$3.53	$3.55	$3.42	$3.39	$3.40	$3.85	$3.94	$4.01	

Notes:

(1) All gas quantities in Dth and rates in $/Dth. (Does not include imbalance purchases traded to storage.)
(2) Weighted Average Cost of Gas (WACOG) at PG&E Citygate
(3) Includes costs to transport gas to PG&E Citygate from alternate delivery points, PG&E stranded pipeline capacity costs, and 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.

Agenda Item 6A

TO:	Board of Directors ABAG POWER	DT:	October 11, 2013
FM:	Herbert L. Pike Chief Financial Officer	RE:	Preliminary Financial Reports --June 2013

We are happy to present the preliminary financial reports for the fiscal year ending June 30, 2013. Highlights of these reports can be summarized as follows:

Natural Gas Pool

As of June 30, 2013, the Natural Gas Pool has about $3.18 million in total assets, including the $2.09 million investment in LAIF. In FY 2012-13, natural gas billings amounted to $7.22 million, but $796 thousand was reclassified as unearned energy revenues to be refunded to the members in FY 2013-14 (in the True-Up). Thus, the Income Statement reflects the net revenue of $6.43 million from natural gas billings and interest income.

The balance of working capital, a refundable deposit from members, amounted to $2.00 million as of June 30, 2012. This $2.00 million is $20 thousand less than the working capital as of the end of the previous three fiscal years. This was due to the refund of $25 thousand one member who left the program offset by a new deposit of $5 thousand for another member who joined. The interest income earned in a year resulting from holding working capital is included as part of the true-up adjustment to be paid in the following year.

Overall revenues were almost 12 percent below budget, with the variance of some $847 thousand being attributed to reduced cost per unit of natural gas and lower than expected usage. Energy costs were less than originally expected resulting in $801 thousand (11.7 percent) less than budget being spent. Of the $6.05 million spent on energy, 44 percent ($2.67 million) was attributed to PG&E pass-through and 56 percent ($3.38 million) to actual cost of energy used. All other operating expenses came in about $48 thousand less than budgeted. Most of this reduction ($35 thousand) is attributable to reduced personnel costs due to Mr. Lahr spreading his hours out to both the POWER program and numerous new grant-funded projects involving energy retrofits, establishing electric vehicle charging stations, energy inventories, and other miscellaneous energy-related projects. Total expense, excluding energy costs, was $384 thousand.

Our auditors are in the process of auditing these financial statements. We expect the audited financial statement will be available in December.

BALANCE SHEET

ABAG POWER POOL - GAS POOL
JUN-13 USD
FINAL

	Total ------------	Natural Gas ------------	Electricity ------------
ASSETS			
CASH IN BANK	698,534.85	698,534.85	0.00
LOCAL AGENCY INVEST. FUND	2,087,752.89	2,087,752.89	0.00
ACCOUNTS RECEIVABLE	42,713.39	42,713.39	0.00
ACCT. REC. POWER POOL SALES	171,649.67	171,649.67	0.00
ACCR. INT. REC. LAIF	1,431.20	1,431.20	0.00
NATURAL GAS INVENTORY	180,608.28	180,608.28	0.00
	------------	------------	------------
TOTAL ASSETS	3,182,690.28	3,182,690.28	0.00
	============	============	============
LIABILITIES			
ACCOUNTS PAYABLE	386,196.69	386,196.69	0.00
UNEARNED ENERGY REVENUES	795,708.48	795,708.48	0.00
WORKING CAPITAL CLIENT DEPOSITS	2,000,785.11	2,000,785.11	0.00
	------------	------------	------------
TOTAL LIABILITIES	3,182,690.28	3,182,690.28	0.00
	------------	------------	------------
FUND EQUITY			
GENERAL EQUITY			
CURRENT YEAR SURPLUS/(DEFICIT)	0.00	0.00	0.00
	------------	------------	------------
TOTAL GENERAL EQUITY	0.00	0.00	0.00
	------------	------------	------------
TOTAL FUND EQUITY	0.00	0.00	0.00
	------------	------------	------------
TOTAL LIABILITIES AND FUND EQUITY	3,182,690.28	3,182,690.28	0.00
	============	============	============

Agenda Item 6B.2

INCOME STATEMENT

ABAG Power Pool - Gas Pool
JUN-13 USD
FINAL

	FY Budget	Actual Current Month	Actual Year-to-date	% of Budget	Budget Balance
REVENUES					
SALE OF ENERGY	7,272,282.00	(194,908.48)	6,424,871.52	(88.35)%	847,410.48
INTEREST INCOME	9,000.00	424.51	7,110.02	(79.00)%	1,889.98
	---------------	---------------	---------------	----------------	---------------
TOTAL REVENUES	7,281,282.00	(194,483.97)	6,431,981.54	(88.34)%	849,300.46
	---------------	---------------	---------------	----------------	---------------
EXPENSES					
COST OF ENERGY					
COST OF ENERGY USED	3,743,855.00	190,642.66	3,381,977.55	90.33%	361,877.45
PG&E PASSTHROUGH	3,105,154.00	175,037.49	2,666,120.19	85.86%	439,033.81
	---------------	---------------	---------------	----------------	---------------
TOTAL COST OF ENERGY	6,849,009.00	365,680.15	6,048,097.74	88.31%	800,911.26
	---------------	---------------	---------------	----------------	---------------
CONSULTANT SERVICES					
LEGAL CONSULTANTS	10,000.00	5,000.00	9,500.00	95.00%	500.00
BILLING AGENT FEES	10,200.00	493.07	(1,377.67)	(13.51)%	11,577.67
SCHEDULING AGENT FEES	38,745.00	3,235.00	38,820.00	100.19%	(75.00)
ABAG FEES	364,328.00	31,920.72	328,850.56	90.26%	35,477.44
	---------------	---------------	---------------	----------------	---------------
TOTAL CONSULTANT SERVICES	423,273.00	40,648.79	375,792.89	88.78%	47,480.11
	---------------	---------------	---------------	----------------	---------------
OTHER DIRECT CHARGES					
INTEREST EXPENSE/BANK CHARGES	9,000.00	564.93	8,090.91	89.90%	909.09
	---------------	---------------	---------------	----------------	---------------
TOTAL OTHER DIRECT CHARGES	9,000.00	564.93	8,090.91	89.90%	909.09
	---------------	---------------	---------------	----------------	---------------
TOTAL EXPENSES	7,281,282.00	406,893.87	6,431,981.54	88.34%	849,300.46
	---------------	---------------	---------------	----------------	---------------
SURPLUS/(DEFICIT)	0.00	(601,377.84)	0.00	n/m	0.00
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ASSOCIATION OF BAY AREA GOVERNMENTS
Representing City and County Governments of the San Francisco Bay Area

DATE: October 17, 2013

TO: ABAG POWER Board of Directors

FROM: Gerald L. Lahr, Manager, ABAG POWER

RE: **Natural Gas Pipeline Capacity Costs**

Summary. California's "core aggregation" program provides retail choice in the core natural gas market by allowing core customers to purchase gas directly from competitive suppliers (Core Transportation Agents or CTAs) rather than from investor owned utilities (IOUs) such as PG&E. ABAG POWER's natural gas aggregation program operates under the policies and regulations applied to all CTAs, and seeks to achieve the dual goals of providing cost savings and price stability to local government agencies.

Since the institution of the core aggregation program, CTAs have steadily gained a customer base throughout PG&E's service territory. In fact, CTAs have gained market share now approaching nineteen percent of PG&E's core market. Pursuant to current California Public Utilities Commission ('Commission' or 'CPUC') regulations, CTAs must take or pay for a share of all long-term interstate pipeline capacity held for core customers by PG&E under contracts that the Commission has approved. Such a requirement jeopardizes CTAs' abilities to compete with PG&E, thereby decreasing value for core customers.

Background. Under previous Commission rulings related to PG&E's natural gas transportation and storage issues (commonly referred to as the 'Gas Accord'),[1] CTAs benefitted from the right to request and receive an assignment of PG&E's core interstate pipeline capacity in monthly or annual increments, but were never obligated to pay for pipeline capacity contracted by PG&E for its core customers that the CTAs did not actually use. In the Gas Accord II (2002) decision, however, the Commission required that, once the January capacity factor for all CTAs reached 10% of PG&E's total January core loads, CTAs would be required to pay for a percentage of PG&E's pipeline and storage capacity in an amount equal to their market share, whether or not CTAs actually used the capacity.

Under this policy, CTAs would have been required to pay for their entire pro rata share of core capacity beginning April 2012 because the January capacity factor for CTAs exceeded 10% prior to April 2011. However, the most recent Gas Accord V Settlement (2011) modified the implementation of the "full cost responsibility" policy adopted in Gas Accord II. Under the CTA Settlement PG&E and a number of CTAs (including ABAG POWER) agreed to a four-year process, beginning in April 2012, for a phase-in of the full cost sharing, which the Commission approved. Under this modified arrangement, after April 2015, each CTA will be required to pay for (but not necessarily hold or use) their entire pro rata share of PG&E's core interstate pipeline capacity. A CTA can continue to take an assignment of PG&E's capacity, and its payment for the use of the assigned capacity contributes to its obligation for the costs of PG&E's capacity.

[1] The original Gas Accord was adopted in 1997 and implemented during the period 1998-2002. Subsequent Gas Accord agreements have generally followed every 2-3 years.

Additionally, as part of the Gas Accord V settlement, PG&E is required to release any capacity that is not accepted by CTAs to the marketplace through an auction, and any revenue from this process will be used to offset the cost responsibility of the CTAs ('unrecovered capacity costs').

In July 2011 ABAG POWER joined with other CTAs ('CTA Consortium') in an effort to further reduce its exposure to the stranded capacity costs created by PG&E. The Consortium hired legal counsel (Winston & Strawn) along with a technical consultant to study the issues and offer advice. Ultimately a decision was made to file a 'Petition to Modify' two prior California Public Utility Commission (CPUC) decisions. A petition was initially filed on May 17, 2012,[2] as follows:

- Modify Decision 03-12-061 to allow CTAs to opt out of an allocation of PG&E's interstate pipeline capacity holdings when the underlying contracts come up for renewal in order to minimize their exposure to stranded costs.
- Replace the requirement set forth in Decision 04-09-022 that PG&E must hold between 962 and 1,058 MMcf/d of interstate pipeline capacity for core customers with a requirement that PG&E must hold interstate capacity in an amount equal to between 100% and 120% of its forecast daily bundled core demand.

ABAG POWER and the Consortium explained that these modifications were being requested in order to:

- Enhance gas supply choice for PG&E's core gas customers
- Allow CTAs and their customers to make their own decisions regarding when and where to purchase gas capacity.
- Reflect the significant reduction in bundled core demand on the PG&E system, compared to growth in pipeline capacity serving California.
- Align the core capacity requirement for PG&E with the core capacity requirement of Southern California Gas Company and San Diego Gas & Electric.
- Automatically accommodate changes in the level of PG&E's bundled core portfolio demand.
- Reduce pipeline capacity costs for all of PG&E's core gas customers.

In December 2012 the CPUC ruled on the above petitions as follows:[3]

- Required PG&E to immediately reduce its winter capacity planning range from the existing 962 – 1,058 MMcf/d to a new range of 900 – 1,000 MMcf/d.
- Required PG&E to file a new application within six months to determine the appropriate level of interstate capacity for PG&E to hold in the future.
- Deferred action on CTAC's request to opt out of future pipeline capacity contracts held by PG&E until the next Gas Transmission & Storage Rate Case to be filed with the Commission in early 2014.

[2] At the time of the initial CPUC filing the membership of the CTA Consortium included: Accent Energy, ABAG POWER, Commercial Energy, School Project for Rate Reduction (SPURR), Tiger Natural Gas and UET/Blue Spruce. Shell Energy North America joined the CTA Consortium as a joint petitioner.
[3] CPUC Decisions 12-12-006 and 12-12-007.

In May and June of this year, ABAG POWER asked member agencies to send letters to the CPUC commissioners supporting our position that CTAs be allowed to make their own decisions regarding gas supply and pipeline capacity, and not be required to accept capacity contracted by PG&E.

In June 2013 PG&E filed an application, as required in the decision, to set a new core interstate pipeline capacity planning range. The CTAC (including ABAG POWER) have filed an initial response to PG&E's filing, and the Administrative Law Judge (ALJ) has provided a procedural schedule that includes: testimony of parties, discovery and potential hearings with a final decision expected in March-April 2014.

To date, ABAG POWER has obligated itself to spending $16,500 for its share of the legal costs associated with this effort.

Discussion. In April 2012 ABAG POWER began receiving invoices from PG&E for the unrecovered pipeline capacity costs in accordance with the Gas Accord V settlement. We are now in the second year of a four-year transition period, and the invoices are currently averaging approximately $15,000/month. ABAG POWER staff currently estimate that the cost burden on the program will increase to approximately $25-30,000/month in 2015 ($310,000/yr), assuming that the CPUC regulations remain unchanged. This cost could overwhelm any potential program savings.

In the past, ABAG POWER has chosen not to utilize the interstate capacity offered to it for a variety of reasons, including: (1) the cost of the capacity is relatively high; (2) the amount of capacity offered varies from pipeline to pipeline creating mismatches that lead to stranded capacity; (3) significant administrative burden in implementing and maintaining contracts with the various pipeline companies; (4) accepting the capacity forces the program to purchase gas based on PG&E's selection of pipelines, thus limiting the program's flexibility to purchase gas at the least cost; (5) the relatively small amounts of capacity offered to ABAG POWER are not in quantities that are preferred by gas suppliers.

While ABAG POWER and its operations team will continue to seek ways to take full advantage of the capacity offerings, due to the reasons stated above we have, so far, concluded that it is more favorable to decline the interstate capacity offerings; allow the rejected capacity to be entered into PG&E's market auction, and accept the revenue that is gained as an offset to the cost.

Conclusion. While the goals of ABAG POWER are not solely related to cost savings, this remains a significant driver of the program, and the unrecovered capacity costs could provide a significant barrier to this objective.

In addition, CTAs as a group desire to maintain their ability to choose for themselves the most economical way to supply the natural gas needs of their customers, rather than being bound by the capacity decisions made by PG&E. ABAG POWER concurs with this desire, and therefore intends to continue to support the efforts of the CTA Consortium. It is hoped that the current proceeding before the CPUC will result in modifications to the current regulations so the program can begin to reduce the expenses associated with the stranded pipeline capacity costs.

ABAG POWER staff, in collaboration with the Executive Committee will continue to monitor the regulatory proceedings as well as the costs associated with this issue to see if any change in strategy or program operation is warranted. If the Executive Committee determines that there are insufficient benefits from the program as a whole, and significant program changes may be necessary, it will call a special meeting of the ABAG POWER Board to discuss the potential options and implications.

/vm