**ATTACHMENT B**

**BACKGROUND**

The Members formed ABAG POWER to operate, among others, the Electric Program. Each Member agreed to pay its share of all costs associated with the Electric Program and appointed ABAG POWER as its agent for the purposes of implementing the Electric Program.

The Electric Program operated under rules promulgated by the California Public Utilities Commission (CPUC), the California Independent System Operator (ISO), the California Power Exchange (PX) and the conventions and practices established by each of the aforementioned entities and by PG&E pursuant to AB 1890 ("Deregulated Market"). The Electric Program provided electricity to accounts specified by each Member under the JPA and DA Agreement as defined in the body of the Wind Up Agreement to which this document is attached.

ABAG POWER is a separate legal entity under the JPA. Each Member is represented on the ABAG POWER Board of Directors (Board). ABAG POWER continues to operate a natural gas aggregation program. All program decisions are made under the policy direction of the Board or the Executive Committee of the Board.

ABAG POWER used the following resources from the described entities in order to implement the Electric Program:

(a) electrical energy from various generators and brokers,
(b) distribution and other services from PG&E,
(c) electric grid services (reliability and control) from the ISO,
(d) schedule coordination (as described below) from NCPA,
(e) billing services from Arizona Public Services (APS), and
(f) administrative and support services from the Association of Bay Area Governments (ABAG).

In addition, ABAG POWER procured occasional services (not relevant to the wind up of the Electric Program) during the operation of the Electric Program. Occasional services included, but are not limited to, financial auditors, attorneys, electric meters sales and installation and meter reading services.

ABAG POWER paid for the resources described above with payments made by the Members. In order to maintain cash flow liquidity, Members funded Working Capital reserves for ABAG POWER through both their monthly payments for electricity and through Working Capital "calls." [1]

Under the Deregulated Market, all electric aggregators were required to pay for ancillary electric services (transmission and distribution costs, system reliability services, etc.) through the ISO. In addition, energy purchases made from the PX required certain security deposits be maintained. The PX and the ISO required such payments be made through a recognized "scheduling coordinator."

---

[1] At the beginning of the program, ABAG POWER billed Members on an estimated "levelized" schedule that included amounts necessary to fund a working capital reserve. This methodology was later abandoned in favor of a monthly bill based on actual expenses and a separate series of calls for working capital contributions from the Members.

ABAG POWER retained NCPA to act as the scheduling coordinator for the Electric Program. NCPA also served as scheduling coordinator for its own members. The Deregulated Market required electric aggregators to deposit funds into two escrow accounts, one with the ISO and the other with the PX. (The latter deposit was only required if the electric aggregator purchased energy from the PX.) NCPA made such deposits on behalf of ABAG POWER. The ISO and PX drew down on the escrow accounts to pay for monthly energy (PX), if any, and electric grid service charges (ISO). The escrow deposit funds were maintained at a level sufficient to pay for 90 days (estimated) worth of energy and ancillary service charges. ABAG POWER paid NCPA the funds necessary to maintain the escrow deposit funds at the required levels. The amounts in the funds were held by NCPA in trust for ABAG POWER.

## WIND UP PLAN

Upon the suspension of the Electric Program, ABAG POWER's billing agent, APS compiled charges attributed to Member accounts. This data indicated that there were service charges for transmission and other services from PG&E (UDC Charges) that had not been invoiced to ABAG POWER in the approximate amount of Three Million Three Hundred Thousand Dollars ($3,300,000). ABAG POWER also experienced a one-week period in August 2000 during which it did not purchase electricity for the Members due to unstable market conditions. Members continued to receive power. ABAG POWER has not been invoiced for the costs of the energy consumed during this period. ABAG POWER estimates this cost to be approximately One Million Four Hundred Thousand Dollars ($1,400,000) (based on load profiling and prevailing energy costs).

Initially, ABAG POWER retained the funds it held in its own accounts to pay for the uninvoiced UDC Charges and energy charges, and to pay ongoing wind up costs. ABAG POWER has concluded that:

(a) some of the uninvoiced UDC Charges were included in the Direct Access Credit calculation (see below),
(b) the balance of the uninvoiced UDC Charges have not been, and may never be invoiced to ABAG POWER (for further discussion see Attachment D), and
(c) the energy charges have not been, and may never be invoiced to ABAG POWER (for further discussion see Attachment D).

Based on the foregoing, ABAG POWER is concluding the wind up of the Electric Program without settling the potential liabilities for UDC Charges and energy described above.

Further, ABAG POWER has concluded that the funds held by NCPA will not be released in the foreseeable future (see below). Therefore, ABAG POWER is concluding the wind up of the Electric Program without having received all of the funds held by NCPA in trust for ABAG POWER in the ISO Escrow Deposit and the PX Escrow Deposit.

Finally, ABAG POWER has settled its claim against PG&E for the Direct Access Credits (see below). ABAG POWER is distributing the funds from the settlement as part of the wind up.

## Direct Access Credit

The Direct Access Credit results from the intersection of CPUC regulations and extraordinarily high prices for electricity in 2000. The following is excerpted from a CPUC draft document that describes what the Direct Access Credit is and how it is derived.[2]

> "Since 1998, PG&E and SCE have offered service to two distinct classes of customers. Bundled service customers received the full range of electric services from the utilities, which include energy procurement and delivery. PG&E and SCE customers could also choose, under the DA option, to purchase energy from an electric service provider (ESP). PG&E and SCE continue to deliver electricity to both [Direct Access] and bundled service customers.
>
> A. Rate Freeze
>
> Total rates were frozen at levels in effect on June 10, 1996 for all customers. Bundled service customers paid these frozen rates for the duration of the transition period (January 1, 1998 through March 31, 2002 or a Commission-authorized earlier end date). These frozen tariff rates included a generation rate component. The generation rate was unbundled into a market price and a competition transition charge (CTC) component. The CTC was calculated residually as the difference between the fixed generation rate component and the market price, where the market price was based on the utility's cost of procuring power from the PX and the California Independent System Operator (ISO). All customers pay the CTC and the CTC revenues were to be used to pay for the utility's stranded generation costs, also known as transition costs.
>
> B. The Avoided Cost Credit
>
> The utilities calculated a market price for billing purposes utilizing the cost and quantities of power purchased from the PX. This PX price was used to determine the contribution to the recovery of CTC (when compared to the generation rate component of frozen rates) and also represented the utilities' avoided cost of procuring energy. The PX component of the generation rate was either applied to recover the cost of purchasing power for bundled service customers or given as a credit to DA customers. The credit reflected the fact that DA customers had chosen to procure their energy through an ESP rather than the utility. So long as the market price, or DA credit, remained below the generation component of the customer's frozen rate, the DA customer continued to make a contribution to CTC in exactly the same manner as a similarly situated bundled service customer.
>
> C. The Zero Minimum Bill Provision
>
> Because the DA credit was based on the market price from the PX, it was possible that the credit would exceed either the generation rate component or the entire bill. If the PX credit exceeded the generation rate component, there was a negative CTC, i.e., no contribution to recovery of stranded costs. If the PX credit exceeded the entire amount of the bill, meaning that the PX credit was greater than the sum of the generation, distribution, transmission, public purpose, and the other rate components, there would be a negative bill. In other words, the DA customer would receive a credit for the entire utility bill. This is also known as a "credit" bill.

[2] See Attachment D description of 1998 RAP – Draft Decision.

> Prior to June 1999, under the adopted tariffs, DA customers receiving the PX credit could experience, at a minimum, a monthly bill of $0. In D.99-06-058, the Commission eliminated the zero minimum bill provision. The elimination of the zero-minimum bill provision allowed DA customers to receive the entire PX credit even if it resulted in a negative (credit) bill. Prior to market dysfunctions in mid 2000, PX credits in excess of total monthly charges were generally carried over to succeeding months and were netted against positive bills.
>
> The dysfunction of California energy markets in 2000 through early 2001, undermined the original basis for calculating the DA credit. The prices charged the utilities during the waning days of the PX were substantially higher than the cost of producing the energy; were regularly higher than the generation component of frozen rates; and in fact, were frequently so high that the DA credit exceeded the entire amount of a DA customer's bill for the services the DA customer did take from the utility and the generation rate component. The PX collapsed in January 2001."

Upon the suspension of the Electric Program, PG&E owed ABAG POWER approximately Twenty-One Million Three Hundred Thousand Dollars ($21,300,000) in unpaid Direct Access Credits. ABAG POWER filed a complaint with the CPUC to collect the credits. The CPUC Complaint was stayed when PG&E filed for Chapter 11 bankruptcy in April 2002. ABAG POWER settled its claim against PG&E for Seventeen Million Dollars ($17,000,000) plus bankruptcy required interest at the rate of 4.19% per annum. PG&E has paid Seventeen Million Dollars ($17,000,000) in principal and Two Million Four Hundred Thousand Dollars ($2,400,000)in interest in fulfillment of the settlement.

## ATTACHMENT C

## FINANCIAL INFORMATION

ABAG POWER settled its DA credit claim with PG&E in late 2002 for $17.0 million plus interest at an annual rate of 4.19% to accrue beginning December 1, 2000. Accordingly, staff reflected this settlement in the financial reports for fiscal year ending June 30, 2003, with all other necessary adjustments incorporated therein to prepare for winding up the Electricity Pool and distributing cash on hand to members by June 30, 2004. The Executive Committee approved all these book adjustments prior to the year-end close, and our independent auditors have completed their audit of the June 30, 2003 financial reports. They expressed an unqualified opinion on these reports with no audit adjustments. Since ABAG POWER has received payment in full plus accrued interest from PG&E for settlement of the DA credit claim in April 2004, the payment dates as listed on the next page are realistic.

Based on the audited financial reports of ABAG POWER for the year ending June 30, 2003 that were duly approved by the Executive Committee at its meeting held on February 18, 2004, the Electricity Pool has $23.8 million in total assets available for distribution to its members (see Exhibit A). Total assets will continue to: (a) Increase by accrued interest from the PG&E settlement and from the pool's investment in the Local Agency Investment Fund, and (b) Decrease by operating expenses necessary to wind up the pool.

On October 27, 2003, the ABAG POWER Board of Directors approved the methodology for winding up the electric program and distributing funds. In accordance with this process, funds in the Electricity Pool will be distributed in three categories.

| **Payable to Members** | **Description** | **Basis of Distribution** |
|---|---|---|
| | | |
| PG&E Distribution | DA Credit settlement less approximately $740,000 (see table on next page) | Total CTC reversal collected from each member |
| Other | Working capital | Total working capital collected from each member |
| Members' Balancing Account | Accumulated operating Surplus/deficit | Total KWH usage |
| | | |

The following table shows balances of total audited assets and proposed disbursements as of June 30, 2003 and current balances as of April 15, 2004 and target dates of distribution.

| | **Audited Balances 6/30/2003 ($'MM)** | **Interim Balances 4/15/2004 ($'MM)** | **Status** | **Target Distribution Date** |
|---|---|---|---|---|
| Total Assets | 23.84 | 24.36 | Will increase by accrued interest net of operating expenses | As stated below |
| **<u>Payable to Members</u>** | | | | |
| PG&E Distribution* | 18.27 | 18.83 | Will not change | 6/15/2004 |
| Other | 5.41 | 5.41 | Will not change | 6/15/2004 |
| Members' Balancing Account | 0.16 | 0.12 | Will decrease by operating expenses | 03/31/05, after the FY 04 audit |
| Total Disbursements | 23.84 | 24.36 | | |

* On February 18, 2004, the Executive Committee approved: (a) retaining $100,000 from the DA Credit settlement to pay for wind up expenses after June 3, 2004 (the residual balance in the hold back fund will be distributed before July 1, 2010), and (b) applying approximately $640,000 from the DA Credit settlement to pay "Other" (Working Capital).

# ABAG POWER Electric Program Allocation & Distribution
## (As of April 15, 2004)

| Members | Grand Total Usage (kWh) (1) | Usage % | Original CTC Reversals | Streetlight Correction | Net CTC Reversals | CTC Reversal % | DA Credit Distribution (2) | Total Working Cap. Deposits (3) | Total Distribution (4) |
|---|---|---|---|---|---|---|---|---|---|
| City of Albany | 3,269,408 | 0.35% | $ 70,514 | $ (37,804) | $ 32,710 | 0.20% | $ 37,440 | $ 13,725 | $ 51,165 |
| Town of Los Altos Hills | 314,682 | 0.03% | 4,274 | | 4,274 | 0.03% | 4,892 | 6,099 | 10,991 |
| City of Antioch | 49,175,835 | 5.21% | 696,703 | (122,580) | 574,122 | 3.51% | 657,142 | 167,352 | 824,494 |
| City of Arcata | 3,562,992 | 0.38% | 79,173 | (25,043) | 54,131 | 0.33% | 61,958 | 29,796 | 91,754 |
| Town of Atherton | 1,898,831 | 0.20% | 27,998 | | 27,998 | 0.17% | 32,047 | 18,123 | 50,170 |
| City of Benicia | 12,064,815 | 1.28% | 251,386 | (74,333) | 177,053 | 1.08% | 202,655 | 88,075 | 290,730 |
| City of Berkeley | 2,696,431 | 0.29% | 193,082 | | 193,082 | 1.18% | 221,003 | 61,428 | 282,431 |
| County of Butte | 19,049,605 | 2.02% | 376,505 | | 376,505 | 2.30% | 430,948 | 119,314 | 550,263 |
| City of Cloverdale | 5,113,484 | 0.54% | 103,456 | | 103,456 | 0.63% | 118,416 | 35,056 | 153,473 |
| County of Monterey | 52,383,320 | 5.55% | 531,804 | (1,915) | 529,889 | 3.24% | 606,512 | 225,794 | 832,306 |
| County of Contra Costa | 138,139,814 | 14.65% | 2,748,664 | (23,395) | 2,725,269 | 16.66% | 3,119,351 | 545,198 | 3,664,549 |
| City of Cotati | 2,629,895 | 0.28% | 37,545 | (130) | 37,415 | 0.23% | 42,825 | 25,935 | 68,760 |
| City of Cupertino | 13,694,587 | 1.45% | 234,959 | (63,383) | 171,575 | 1.05% | 196,386 | 92,444 | 288,830 |
| City of Daly City | 41,194,260 | 4.37% | 1,417,366 | (165,064) | 1,252,303 | 7.65% | 1,433,390 | 130,117 | 1,563,507 |
| City of Davis | 2,207,730 | 0.23% | 34,764 | (21,751) | 13,013 | 0.08% | 14,894 | 20,009 | 34,903 |
| City of El Cerrito | 3,404,997 | 0.36% | 57,838 | | 57,838 | 0.35% | 66,202 | 32,320 | 98,522 |
| City of Foster City | 13,133,829 | 1.39% | 301,085 | (109,981) | 191,104 | 1.17% | 218,738 | 68,016 | 286,754 |
| Golden Gate Bridge District | 13,208,235 | 1.40% | 355,647 | | 355,647 | 2.17% | 407,074 | 45,318 | 452,392 |
| City of Gonzales | 3,741,591 | 0.40% | 54,963 | (2,040) | 52,923 | 0.32% | 60,576 | 36,264 | 96,840 |
| City of Half Moon Bay | 1,888,466 | 0.20% | 25,108 | | 25,108 | 0.15% | 28,738 | 14,071 | 42,810 |
| H.A.R.D. | 8,386,287 | 0.89% | 135,566 | | 135,566 | 0.83% | 155,170 | 84,911 | 240,080 |
| City of Hercules | 5,239,548 | 0.56% | 89,938 | (12,002) | 77,935 | 0.48% | 89,205 | 56,859 | 146,064 |
| Town of Hillsborough | 7,611,796 | 0.81% | 107,637 | | 107,637 | 0.66% | 123,201 | 76,024 | 199,226 |
| Housing Auth. Co. of Alameda | 1,248,447 | 0.13% | 23,420 | | 23,420 | 0.14% | 26,806 | 18,003 | 44,810 |
| City of Los Altos | 5,152,008 | 0.55% | 73,385 | | 73,385 | 0.45% | 83,996 | 41,289 | 125,285 |
| Los Trancos Co. Water District | 670,686 | 0.07% | 4,646 | | 4,646 | 0.03% | 5,318 | 6,698 | 12,016 |
| City of Menlo Park | 11,546,594 | 1.22% | 267,524 | (71,150) | 196,373 | 1.20% | 224,769 | 82,908 | 307,678 |
| City of Millbrae | 5,241,722 | 0.56% | 103,562 | (58,891) | 44,670 | 0.27% | 51,130 | 37,973 | 89,102 |
| City of Mill Valley | 10,532,429 | 1.12% | 204,374 | (26,042) | 178,332 | 1.09% | 204,119 | 94,946 | 299,065 |
| City of Milpitas | 11,013,448 | 1.17% | 276,838 | | 276,838 | 1.69% | 316,870 | 83,865 | 400,734 |
| Town of Moraga | 1,768,987 | 0.19% | 12,800 | | 12,800 | 0.08% | 14,650 | 12,503 | 27,153 |
| County of Napa | 14,477,518 | 1.53% | 383,200 | (1,297) | 381,903 | 2.33% | 437,128 | 73,627 | 510,755 |
| City of Newark | 8,728,855 | 0.93% | 174,076 | (85,209) | 88,868 | 0.54% | 101,718 | 81,536 | 183,254 |
| City of Orinda | 1,602,274 | 0.17% | 19,135 | (1,122) | 18,013 | 0.11% | 20,618 | 18,433 | 39,051 |
| City of Pacifica | 8,145,529 | 0.86% | 165,604 | (67,092) | 98,512 | 0.60% | 112,757 | 49,496 | 162,253 |
| City of Patterson | 6,354,738 | 0.67% | 222,030 | (3,126) | 218,904 | 1.34% | 250,558 | 35,892 | 286,450 |
| City of Petaluma | 36,118,882 | 3.83% | 457,781 | (120,246) | 337,535 | 2.06% | 386,344 | 196,030 | 582,373 |

# ABAG POWER Electric Program Allocation & Distribution
**(As of April 15, 2004)**

| Members | Grand Total Usage (kWh) (1) | Usage % | Original CTC Reversals | Streetlight Correction | Net CTC Reversals | CTC Reversal % | DA Credit Distribution (2) | Total Working Cap. Deposits (3) | Total Distribution (4) |
|---|---|---|---|---|---|---|---|---|---|
| City of Pinole | 9,446,916 | 1.00% | 252,199 | | 252,199 | 1.54% | 288,668 | 22,875 | 311,543 |
| City of Pleasanton | 28,757,666 | 3.05% | 511,098 | (133,465) | 377,633 | 2.31% | 432,240 | 182,101 | 614,341 |
| R.A.F.C. | 11,869,270 | 1.26% | 225,935 | | 225,935 | 1.38% | 258,606 | 155,745 | 414,351 |
| City of Salinas | 26,619,689 | 2.82% | 466,324 | (262,362) | 203,961 | 1.25% | 233,455 | 133,488 | 366,943 |
| City of San Carlos | 6,896,150 | 0.73% | 160,947 | (65,873) | 95,074 | 0.58% | 108,822 | 42,589 | 151,412 |
| City of San Leandro | 32,799,800 | 3.48% | 686,521 | (199,508) | 487,013 | 2.98% | 557,436 | 157,723 | 715,160 |
| City of San Mateo | 29,749,102 | 3.15% | 688,758 | (276,868) | 411,890 | 2.52% | 471,450 | 189,375 | 660,825 |
| County of San Mateo | 98,391,072 | 10.43% | 2,109,359 | (71,151) | 2,038,208 | 12.46% | 2,332,939 | 604,514 | 2,937,453 |
| City of San Pablo | 6,222,193 | 0.66% | 82,505 | | 82,505 | 0.50% | 94,436 | 47,404 | 141,840 |
| City of Santa Rosa | 54,963,333 | 5.83% | 854,324 | (194,168) | 660,156 | 4.04% | 755,616 | 296,993 | 1,052,609 |
| City of Saratoga | 2,899,035 | 0.31% | 38,110 | (2,929) | 35,181 | 0.22% | 40,269 | 24,666 | 64,934 |
| County of Sonoma | 4,805,048 | 0.51% | 53,841 | | 53,841 | 0.33% | 61,627 | 39,725 | 101,352 |
| South Co. Fire Authority | 601,994 | 0.06% | 13,289 | | 13,289 | 0.08% | 15,211 | 5,979 | 21,189 |
| City of Union City | 1,911,061 | 0.20% | 59,927 | | 59,927 | 0.37% | 68,592 | 8,269 | 76,861 |
| City of Vacaville | 5,162,752 | 0.55% | 93,369 | | 93,369 | 0.57% | 106,871 | 57,524 | 164,394 |
| City of Vallejo | 60,985,603 | 6.47% | 1,212,306 | | 1,212,306 | 7.41% | 1,387,609 | 353,803 | 1,741,413 |
| West County Wastewater Dist. | 13,699,914 | 1.45% | 459,806 | (9) | 459,797 | 2.81% | 526,285 | 136,567 | 662,852 |
| Town of Windsor | 16,479,736 | 1.75% | 328,111 | (1,362) | 326,749 | 2.00% | 373,998 | 90,454 | 464,451 |
| City of Winters | 4,366,833 | 0.46% | 40,360 | | 40,360 | 0.25% | 46,196 | 39,032 | 85,228 |
| GL WriteOn | | | (2) | | (2) | | (2) | | (2) |
| Total (4) | 943,239,722 | 100% | 18,661,435 | (2,301,293) | 16,360,141 | 100% | 18,725,870 | 5,414,272 | 24,140,142 |

Notes
(1) Total usage for entire program period. Data from billing agent (APS) for billing periods 4/98 - 7/01.
(2) Total of Net CTC Reversals, plus interest on bankruptcy claim, minus $100,000 hold back amount. This is equivalent to the bankruptcy claim principal and interest ($19,465,729), less $639,859 allocated for repayment of Working Capital, minus $100,000 hold back amount.
(3) Total of "Working Capital Client Deposits" and "PX and ISO Client Deposits."
(4) Does not include Members Balancing Account, or ISO and PX escrow deposits with NCPA.

# ATTACHMENT D

# CONTINGENT RISKS

## RISK ANALYSIS

Attached as Exhibit A is a table setting forth ABAG POWER's best reasonable effort at estimating the maximum reasonable liability (in total for the Electric Program) for each of the listed contingent liabilities. The table allocates total liability of the program to individual Members in accordance with the usage ratio, or CTC Reversal ratio, as appropriate. The allocation is for illustrative purposes only. ABAG POWER does not have sufficient information on which to base an estimate of how the entity imposing the liability would allocate the liabilities or how ABAG POWER and the Members ought to react to such allocation.

## A. UNINVOICED ENERGY CHARGES

Description of Risk

ABAG POWER is distributing to each of its Electric Program Members a proportionate share of the Working Capital contributions made by Members in response to Working Capital calls by ABAG POWER and residual funds from operating costs paid by Members during the Electric Program (Balancing Account). These funds were held, in part, in reserve for payment of charges for electrical energy consumed by Members of the Electrical Program during a one-week period in August 2001 when ABAG POWER was not purchasing electricity on behalf of the Electric Program (Gap Period).

As of February 29, 2004, ABAG POWER has not been invoiced for electricity consumed during the Gap Period. Under the Wind Up Agreement, if ABAG POWER receives such a bill, each Member will be required to pay its proportionate share.

Background

Under normal operating conditions, ABAG POWER purchased on behalf of the Members of the Electric Program sufficient energy to meet their estimated needs. Purchases were made from a variety of electricity generators and energy remarketers, under various contractual formats (fixed price, indexed price, indexed price with "floors" and/or "ceilings," etc.), and at various prices. In all instances, one significant factor in the price of electricity is the hour in which it is consumed. Energy during certain "peak" periods was priced considerably higher than at other periods.

In the summer of 2000, the electric market became highly unstable. ABAG POWER was having a difficult time meeting credit requirements which our scheduling coordinator and electricity sellers were imposing on the marketplace. Consequently, on August 2, 2000 ABAG POWER notified PG&E in writing of its difficulties, and actions being taken to rectify the situation. PG&E acknowledged that it had received ABAG POWER's notice, and although it believed that ABAG POWER was in default of its ESP Agreement, PG&E would allow ABAG POWER until August 7, 2000 to resolve the situation. Prior to this deadline, ABAG POWER was able to secure scheduling coordination services and contract for electricity at a reasonable price, without the additional credit requirements imposed by other energy providers and remarketers.

Legal Analysis

From a legal perspective, the matter is a simple collection issue. Since ABAG POWER did not enter into a contract during the Gap Period, there is no “seller” to invoice ABAG POWER for any energy that was consumed. There are only two sources of electricity flowing into the California grid that could have serviced the Electric Program during the Gap Period: the ISO and PG&E.

The energy consumed by the Members could have been supplied through the ISO “imbalance energy.” This is a reserve maintained by the ISO when contracted for energy supplies from PG&E and other electric service providers fall below the amount necessary to keep the grid operational. Electricity Program electricity consumption during the Gap Period could have come from this source.

Alternatively, PG&E supplies such a large amount of electricity over any period of time that it could have been supplying part of the power for the Electric Program during the Gap Period.

The risk of incurring the liability is wholly dependent on the ability either of the ISO or of PG&E to “prove” that electricity consumed by Members during this period was supplied by the party making the claim.

ABAG POWER is without sufficient information to evaluate the likelihood of this risk occurring.

ABAG POWER has reviewed the price of imbalance energy for the period in question. Imbalance energy prices tend to be the highest of all prices paid for electricity. Based on the price for imbalance energy an estimate of the amount of electricity that the Electric Program would have consumed during the Gap Period, the maximum exposure is estimated as One Million Four Hundred Twenty Thousand Dollars ($1,420,000).

Finally, ABAG POWER notes that as time goes on the ability of either the ISO or PG&E to collect the data necessary to generate an invoice and prove a claim diminishes.

## B. UDC CHARGES

Description of Risk

From information provided by the Program’s billing agent (APS) we believe there may be UDC charges for which neither ABAG POWER nor its Members have been invoiced by PG&E. During the period July 2000 to June 2001 the amount of UDC charges billed to members (and collected by ABAG POWER) is greater than the amount invoiced from PG&E.

ABAG POWER is also aware of one instance in which UDC charges for the affected period were generated by PG&E in connection with an electric account for a Member’s streetlight system. These accounts are unique in the PG&E billing system. Electricity consumed by a streetlight system is not metered and is charged on an estimated consumption basis. In the case of which ABAG POWER is aware, the Member had already paid PG&E for the asserted UDC charges.

Based on APS Billing information and information from ABAG POWER's review of the DA Credit's owed by PG&E, ABAG POWER has concluded that the likely total exposure is approximately One Million Six Hundred Thousand Dollars ($1,600,000).

LEGAL ANALYSIS

PG&E applies UDC charges to individual accounts based on the amount of electricity consumed.

As noted above, streetlight accounts are uniquely billed by PG&E. In the case that has come to ABAG POWER's attention, we believe that the Member has been billed twice for the same UDC charges. Other Members with streetlight accounts may encounter the same situation.

### C. ISO ESCROW DEPOSIT AND PX ESCROW DEPOSIT

Description of Risk

The PX Escrow Deposit and ISO Escrow Deposit held by NCPA on behalf of ABAG POWER are subject to reduction or nonrefund. In the case of PX Escrow Deposit, all of the funds may be consumed in the course of settling the PX's bankruptcy claims. The ISO Escrow Deposit is subject to adjustments based on FERC ordered energy price rollbacks (see detailed description in Section D below). The FERC ordered rollbacks can both increase and decrease the ISO Escrow Deposit.

ABAG POWER bought electricity for use by the Electric Program and sold excess capacity into the marketplace at various times. At those instances in which ABAG POWER was purchasing electricity, the FERC ordered price reductions will generate a refund and an increase in the ISO Escrow Deposit. In those instances in which ABAG POWER sold energy into the marketplace, the FERC ordered rollbacks can reduce the amount available from the ISO Escrow Deposit. Based on ABAG POWER's review of the total amount of power sold during the period under consideration by FERC for price reductions, we conclude that the likely reductions do not exceed the amounts currently in the ISO Escrow Deposit.

Under these circumstances, we believe the risk is nominal.

### D. DIRECT ACCESS CREDITS

Description of Risk

ABAG POWER is distributing to each of its Electric Program Members a proportionate share of the funds received from PG&E as settlement of ABAG POWER's claim against PG&E for Direct Access Credits incurred during 2000 under the deregulated energy market in California. The Direct Access Credit is a result of the application of a rate formula adopted by the CPUC. The formula includes contemporaneous energy prices and the Direct Access Credit is a by-product of high electricity prices in 2000.[1]

The FERC has been engaged in a proceeding to determine whether wholesale prices charged by electricity generators and marketers during 2000 in California were "just and reasonable." FERC has already found that at certain times such prices were not. The FERC

[1] For a detailed description of Direct Access Credits, see Appendix A, "Direct Access Credit."

proceeding is now trying to determine what "just and reasonable" rates should have been during specific times.[2] The outcome will be an order requiring generators and marketers who overcharged to refund money to purchasers.

In principle, the CPUC has the power to recalculate the Direct Access Credit based on the FERC ordered reduction in electricity prices. However, FERC has no jurisdiction over the CPUC and cannot compel such a recalculation. The result of such a recalculation would be a reduction in the amount of Direct Access Credit owed ABAG POWER.[3] The CPUC can undertake a regulatory process referred to as ratemaking in which the ultimate result could be the imposition of a surcharge on Electric Program Member accounts to recoup overpaid Direct Access Credits over a specified time period, or immediately.

This risk exposure is punctuated by §4 of the Stipulation and Release under which PG&E and ABAG POWER are settling the Direct Access Credit claim (Stipulation and Release). §4 states:

> "[ABAG POWER] and PG&E expressly agree that this Stipulation and Release is a compromise and settlement of all claims and matters that are disputed as between the parties involving the 1998 RAP for the period through and including June 30, 2001, all issues that were raised, or could have been raised, in the CPUC Complaint, and all issues that were raised, or could have been raised, in the Claim. *In the event that the CPUC issues any future ruling relating to the direct access credits at issue in the Claim, the CPUC Complaint or the 1998 RAP, the parties will use their best efforts to preserve the intent of this Stipulation and Release, consistent with applicable law*." [4] (emphasis added)

This provision was negotiated when PG&E declined to give ABAG POWER a full indemnity against the possibility that the CPUC will take an action to impose a surcharge to recover Direct Access Credits paid to ABAG POWER (or its electricity members). PG&E agreed that the exposure exists but asserts that it cannot, as an entity regulated by the CPUC, agree to make ABAG POWER whole in the event of an adverse CPUC action. PG&E asserts that an indemnity provision would be characterized as an illegal circumvention (by PG&E) of the CPUC. ABAG POWER acceded to PG&E's argument and §4 is the negotiated compromise.

<u>Background</u>

On December 22, 2003, the U.S. Bankruptcy Court for Northern California, San Francisco Division confirmed a Plan of Reorganization for PG&E (Confirmed Plan). The Direct Access Credit was paid to ABAG POWER under the Stipulation and Release. The Stipulation and Release was approved by the court and is included in the Confirmed Plan as a Class 7 Claim.

During the bankruptcy proceedings, PG&E and the CPUC submitted competing plans for the reorganization of PG&E. Simultaneously, PG&E was pursuing claims challenging certain actions by the CPUC during deregulation (CPUC Proceedings). Further, PG&E filed suit in Federal District Court for Northern California against the CPUC challenging various aspects of the deregulated energy market created under CPUC regulations and guidance. The CPUC

---

[2] Pricing occurred on an hourly basis.

[3] One estimate of the impact of known (in Spring 2003) FERC ordered reductions on ABAG POWER's Direct Access Credit resulted in a reduction of $4-5 million in Direct Access Credits owed. ABAG POWER believes the estimate to be reasonable.

[4] The "1998 RAP" is the ratesetting proceeding described below under the same name. The "CPUC Complaint" is ABAG POWER's initial complaint filed with the CPUC for payment of the Direct Access Credit.

and PG&E reached a Master Settlement Agreement on all pending disputes, including those before the Bankruptcy Court. The Master Settlement Agreement dismissed the lawsuits and the CPUC Proceedings with prejudice, and committed both parties to supporting and implementing what ultimately became the Confirmed Plan. The dismissed CPUC proceedings do not include the 1998 RAP or ABAG POWER's CPUC Complaint. The CPUC action to approve the Confirmed Plan and the Master Settlement Agreement is documented in the opinion issued for Investigation 02-04-026 (Settlement Opinion).

The Master Settlement Agreement between the CPUC and PG&E has the following relevant features:

1. The CPUC agreed to include certain cost components in the CPUC's future regulatory and ratemaking proceedings as they affect PG&E. Such cost components included the sum of $2.2 billion designated the "regulatory asset." Rates established by the CPUC must be sufficient to (a) support all of the cost components necessary to PG&E's continued viability as an ongoing public utility and (b) amortize the regulatory asset over a period of ten (10) years.
2. Within the constraints of the Confirmed Plan and the Master Settlement Agreement, the CPUC retains its regulatory authority over PG&E.
3. The current CPUC and future CPUCs are bound by the Master Settlement Agreement.
4. The CPUC acknowledges the continuing jurisdiction of the Bankruptcy Court to enforce the Confirmed Plan.

Legal Analysis

The potential CPUC regulatory action on the Direct Access Credit can only be triggered by a FERC ordered reduction in wholesale electricity energy prices for 2000. Only PG&E and a Direct Access Credit recipient have standing to initiate an action to recalculate the Direct Access Credit. PG&E and ABAG POWER are estopped from so doing by §4 of the Stipulation and Release (see below). A recalculation of the Direct Access Credit can in theory be initiated by the CPUC. The impetus for a CPUC action is bureaucratic and triggered by FERC ordered price reductions.

The central question is whether the CPUC can legally do so in the face of ABAG POWER's objections. The issue of recalculating Direct Access Credits based on FERC ordered refunds was raised by PG&E in a ratemaking action before the CPUC (Application 98-07-003, the "1998 RAP" filed in 1998). The Administrative Law Judge (ALJ) issued a draft decision on April 3, 2003 but the CPUC has not taken any action on it and it is not currently on the CPUC agenda for consideration, public hearing or further action.[5]

The 1998 RAP - Draft Decision states in pertinent part:

> "In our opinion it would be unreasonable to recompute the [Direct Access] credit should FERC order refunds. We are confronted, initially, with three unknown factors: whether FERC will order refunds: when FERC will order refunds (and when the order become[s] final), and the amount of those refunds.[i] As of this writing, FERC has the matter under consideration. Any order of refunds, if substantial, is expected to be appealed. It is impossible to predict the date of a final order. The period in question, December 28, 2000 to January 18, 2001, is two years old and counting. It is unfair for

[5] No action can be taken without CPUC approval. Draft ALJ decisions on deregulation matters have had a mixed reception before the CPUC. Some have been adopted as presented. Others have been subject to substantial revision. The draft decision is Opinion Adopting a Post Power Exchange Direct Access Credit for Pacific Gas and Electric Company (1998 RAP - Draft Decision).

> ratepayers who paid their utility bills two years ago to be subject to an unknown liability to be paid at an unknown future date. We need not elaborate on the intensive effort required by PG&E to recomputed individual bills nor the intensive efforts and spent resources of end users to verify those recomputed bills. Because we deny PG&E's proposal we do not reach the question of whether approval of the proposal would constitute retroactive ratemaking."
>
> ____________________
>
> [i] When we speak of refunds in this context, we refer not to money going back to DA [direct access] customers, but to a recommendation of their credit. If a refund is ordered, the credit would have been less and the DA customer would have been overpaid by PG&E thereby causing a repayment to PG&E.

The same logistical objections raised by the ALJ to retroactive reductions in Direct Access Credits still stand and are amplified by the passage of yet another year since issuance of the 1998 RAP – Draft Decision and without further action by FERC.[6] Further, the legal barriers to "retroactive ratemaking," which the draft decision avoids, become a live issue.

Independent of the arguments made in the 1998 RAP - Draft Decision, a strong legal argument can be made that the CPUC is estopped by the Settlement Opinion and Master Settlement Agreement from reducing the amount of the Direct Access Credit paid to ABAG POWER.

The Settlement Opinion makes the following policy finding: "It is in the public interest that PG&E emerge from bankruptcy promptly….To emerge from bankruptcy PG&E should pay its creditors. *All allowed claims should be paid in full*. (emphasis added)"[7] On the date of the Settlement Decision, ABAG POWER's Stipulation and Release was an "allowed claim" and part of the record before the CPUC. It will be difficult for the CPUC to defeat the argument that it is estopped from taking any (otherwise permitted) action that effectively modifies the Stipulation and Release or reduces the payment required by the Stipulation and Release. In addition, the Master Settlement Agreement states: "[PG&E and the CPUC] agree not to contest the validity and enforceability of [the Master Settlement Agreement], the [Confirmed Plan] or any order entered by the [Bankruptcy Court] contemplated by or required to supplement [the Master Settlement Agreement and the Confirmed Plan]."[8]

Ancillary Analysis

In addition to the "logic" of a bureaucratic recalculation of the Direct Access Credits in response to the anticipated FERC ordered price reductions, there might be pressure on the CPUC to recover Direct Access Credits to reduce general utility rates. In response, one can raise the objection stated in the 1998 RAP – Draft Decision that the costs to recalculate and recover "overpaid" credits may well exceed the recovery. Finally, please note that the post-bankruptcy CPUC ratemaking structure for PG&E includes the "regulatory asset." Under the terms of the Confirmed Plan and the Master Settlement Agreement, the amount of the regulatory asset which must be amortized by ongoing electric rates will be reduced by any monies actually recovered by PG&E as a result of the same FERC price rollback.[9] The direct

[6] Although, the contested time period misses most of the times during which ABAG POWER's Direct Access Credit was generated. The same legal arguments apply and the FERC proceeding has expanded the timeframe for potential price rollbacks to include more of the period in which ABAG POWER's credits were "generated."
[7] Settlement Decision, p. 78.
[8] Master Settlement Agreement, p. 18, §21.
[9] Master Settlement Agreement, pp. 8-9, §2.d.

effect of the FERC ordered rollback brings significant rate relief under the Confirmed Plan.[10] In the context of generalized rate relief, it appears doubtful that the CPUC would be willing to undertake the ironic step of imposing a surcharge on certain classes of customers (including local government entities such as ABAG POWER's electricity members) in order to wring out the last bitter drop of savings generated by the FERC ordered refunds. Another impediment to such action by the CPUC is the specter of resurrecting the public debate about California's failed energy deregulation program.

Conclusion

The CPUC has the theoretical ability to reduce the Direct Access Credits paid to ABAG POWER. However, ABAG POWER can pose the following legal argument in position: (a) the CPUC is estopped from so doing by the CPUC's findings and actions in reaching the Master Settlement Agreement with PG&E, and the CPUC's support for the Confirmed Plan under which the credits were paid, and (b) the logistical and equity issues raised in the 1998 RAP – Draft Decision. In the absence of any motivation to undertake such a step other than bureaucratic purity of process, ABAG POWER's opinion is that the risk is nominal.

[10] Master Settlement Agreement estimates a potential recovery by PG&E of _________ ($_____) in FERC ordered price reductions.

# EXHIBIT A
# TO ATTACHMENT D

## Allocation of Estimated Contingent Liabilities.

This table illustrates the allocation of ABAG POWER's estimate of the Electric Program liability for the denoted charges among Electric Program members. Allocated amounts have been rounded to the nearest 10 dollars. Please see Attachment D for an explanation of the methodology and basis for this

| Members | (A) Uninvoiced Energy Charges (1) $1,420,000 | (B) UDC Charges (2) $1,600,000 | (D) Direct Access Credits (3) $4,676,000 | Total |
|---|---|---|---|---|
| City of Albany | $ 4,920 | $ 5,550 | $ 9,350 | $ 19,820 |
| Town of Los Altos Hills | 470 | 530 | 1,220 | 2,220 |
| City of Antioch | 74,030 | 83,420 | 164,090 | 321,540 |
| City of Arcata | 5,360 | 6,040 | 15,470 | 26,870 |
| Town of Atherton | 2,860 | 3,220 | 8,000 | 14,080 |
| City of Benicia | 18,160 | 20,470 | 50,600 | 89,230 |
| City of Berkeley | 4,060 | 4,570 | 55,190 | 63,820 |
| County of Butte | 28,680 | 32,310 | 107,610 | 168,600 |
| City of Cloverdale | 7,700 | 8,670 | 29,570 | 45,940 |
| County of Monterey | 78,860 | 88,860 | 151,450 | 319,170 |
| County of Contra Costa | 207,960 | 234,320 | 778,930 | 1,221,210 |
| City of Cotati | 3,960 | 4,460 | 10,690 | 19,110 |
| City of Cupertino | 20,620 | 23,230 | 49,040 | 92,890 |
| City of Daly City | 62,020 | 69,880 | 357,930 | 489,830 |
| City of Davis | 3,320 | 3,740 | 3,720 | 10,780 |
| City of El Cerrito | 5,130 | 5,780 | 16,530 | 27,440 |
| City of Foster City | 19,770 | 22,280 | 54,620 | 96,670 |
| Golden Gate Bridge District | 19,880 | 22,400 | 101,650 | 143,930 |
| City of Gonzales | 5,630 | 6,350 | 15,130 | 27,110 |
| City of Half Moon Bay | 2,840 | 3,200 | 7,180 | 13,220 |
| H.A.R.D. | 12,630 | 14,230 | 38,750 | 65,610 |
| City of Hercules | 7,890 | 8,890 | 22,280 | 39,060 |
| Town of Hillsborough | 11,460 | 12,910 | 30,760 | 55,130 |
| Housing Auth. Co. of Alameda | 1,880 | 2,120 | 6,690 | 10,690 |
| City of Los Altos | 7,760 | 8,740 | 20,970 | 37,470 |
| Los Trancos Co. Water District | 1,010 | 1,140 | 1,330 | 3,480 |
| City of Menlo Park | 17,380 | 19,590 | 56,130 | 93,100 |
| City of Millbrae | 7,890 | 8,890 | 12,770 | 29,550 |
| City of Mill Valley | 15,860 | 17,870 | 50,970 | 84,700 |
| City of Milpitas | 16,580 | 18,680 | 79,120 | 114,380 |
| Town of Moraga | 2,660 | 3,000 | 3,660 | 9,320 |
| County of Napa | 21,800 | 24,560 | 109,150 | 155,510 |
| City of Newark | 13,140 | 14,810 | 25,400 | 53,350 |
| City of Orinda | 2,410 | 2,720 | 5,150 | 10,280 |
| City of Pacifica | 12,260 | 13,820 | 28,160 | 54,240 |
| City of Patterson | 9,570 | 10,780 | 62,570 | 82,920 |
| City of Petaluma | 54,380 | 61,270 | 96,470 | 212,120 |
| City of Pinole | 14,220 | 16,020 | 72,080 | 102,320 |
| City of Pleasanton | 43,290 | 48,780 | 107,930 | 200,000 |
| R.A.F.C. | 17,870 | 20,130 | 64,580 | 102,580 |
| City of Salinas | 40,070 | 45,150 | 58,300 | 143,520 |

# EXHIBIT A
# TO ATTACHMENT D

## Allocation of Estimated Contingent Liabilities.

This table illustrates the allocation of ABAG POWER's estimate of the Electric Program liability for the denoted charges among Electric Program members. Allocated amounts have been rounded to the nearest 10 dollars. Please see Attachment D for an explanation of the methodology and basis for this

| Members | (A) Uninvoiced Energy Charges (1) $1,420,000 | (B) UDC Charges (2) $1,600,000 | (D) Direct Access Credits (3) $4,676,000 | Total |
|---|---|---|---|---|
| City of San Carlos | 10,380 | 11,700 | 27,170 | 49,250 |
| City of San Leandro | 49,380 | 55,640 | 139,200 | 244,220 |
| City of San Mateo | 44,790 | 50,460 | 117,720 | 212,970 |
| County of San Mateo | 148,120 | 166,900 | 582,550 | 897,570 |
| City of San Pablo | 9,370 | 10,550 | 23,580 | 43,500 |
| City of Santa Rosa | 82,740 | 93,230 | 188,680 | 364,650 |
| City of Saratoga | 4,360 | 4,920 | 10,060 | 19,340 |
| County of Sonoma | 7,230 | 8,150 | 15,390 | 30,770 |
| South Co. Fire Authority | 910 | 1,020 | 3,800 | 5,730 |
| City of Union City | 2,880 | 3,240 | 17,130 | 23,250 |
| City of Vacaville | 7,770 | 8,760 | 26,690 | 43,220 |
| City of Vallejo | 91,810 | 103,450 | 346,500 | 541,760 |
| West County Wastewater Dist. | 20,620 | 23,240 | 131,420 | 175,280 |
| Town of Windsor | 24,810 | 27,950 | 93,390 | 146,150 |
| City of Winters | 6,570 | 7,410 | 11,540 | 25,520 |
| Total | $ 1,419,980 | $ 1,600,000 | $ 4,676,010 | $ 7,695,990 |

Notes:
(1) Allocated by kWh usage
(2) Allocated by kWh usage

(3) Allocated on CTC Credit Reversals. Represents PG&E's estimate of the possible reduction in the CTC credits due to the FERC price mitigation hearings.