ELECTRIC SCHEDULE TBCC
TRANSITIONAL BUNDLED COMMODITY COST

APPLICABILITY: This schedule applies to Direct Access and Community Choice Aggregation Service customers who: (1) elect Transitional Bundled Service (TBS) as prescribed in Rule 22.1 (Direct Access Service Switching Exemption Rules); or (2) who take Bundled Service prior to the end of the mandatory six-month notice period required to elect Bundled Service as prescribed in Rules 22.1 and 23 (Community Choice Aggregation Service).

TERRITORY: Schedule TBCC applies everywhere PG&E provides electric service as shown in Preliminary Statement, Part A.

RATES: This schedule will apply where the Transitional Bundled Commodity Cost (TBCC) is required for calculation of applicable power charges.

Direct Access customers who elect: (1) TBS as prescribed in Rule 22.1; or (2) take Bundled Service prior to the end of the mandatory six-month notice period required to elect Bundled Service as prescribed in Rule 22.1 will be charged the TBCC in addition to transmission, transmission rate adjustments reliability services, distribution, conservation incentive adjustment, public purpose programs, nuclear decommissioning and New System Generation Charges on (T) the customer's otherwise applicable tariff, and the Direct Access Cost Responsibility Surcharge applicable under Schedule DA CRS for the duration of the period. The TBCC used for billing will consist of the market prices set forth below, adjusted by a Renewable Portfolio Standard (RPS) adder, a Capacity adder (CAP ADDER), and an allowance for Revenue Fees and Uncollectible (RF&U) account expense and Distribution Loss Factors (DLFs).

Community Choice Aggregation service customers who elect to take bundled service prior to the end of the mandatory six-month notice period required to elect bundled Service as prescribed in Rule 23 will be charged the TBCC in addition to transmission, transmission rate adjustments, reliability services, distribution, conservation incentive adjustment, public purpose programs, nuclear decommissioning and New System Generation Charges on the (T) customer's otherwise applicable tariff, and the Community Choice Aggregation Cost Responsibility Surcharge applicable under Schedule CCA CRS for the duration of the period. The TBCC used for billing will consist of the market prices set forth below, adjusted by a RPS adder, a CAP ADDER, and an allowance for Revenue Fees and Uncollectible (RF&U) account expense and Distribution Loss Factors (DLFs).

(D)

(Continued)

ELECTRIC SCHEDULE TBCC Sheet 2
TRANSITIONAL BUNDLED COMMODITY COST

RATES: (Cont'd.)

Development of the Hourly Market Prices

1. Hourly Market Price at the Transmission/Distribution Interface (T)

The hourly market price (Hourly Market Price or MP) at the transmission / distribution interface, shall consist of the California Independent System Operator (CAISO) hourly Integrated Forward Market (IFM) Locational Marginal Price (LMP) for the PGE Utility Distribution Company (UDC) control Area (LAP_PGAE), multiplied by an allowance for Unaccounted for Energy (UFE), plus an allowance for Ancillary Services and the Independent System Operator (ISO) Grid Management Charges (GMC). (T) (T) (T) (T)

MP = IFM LMP * UFE + AS + GMC (N)

The UFE allowance will equal one plus the straight average of the most recent six month actual UFE percentages available from the ISO Management Report for the Board of Governors posted on the CAISO website. The UFE allowance will be revised semi-annually (January and July).

The allowance for Ancillary Services, calculated hourly, will equal the ISO's corresponding Ancillary Service Marginal Price (ASMP) Day Ahead (IFM) and Hour Ahead/Real Time (HASP/RT) Regional Ancillary Services procurement costs divided by the UDC control area system load. If regional Ancillary Services (A/S) data or UDC control area system load data is not made publicly available in a timely manner, the rate will be derived from the Ancillary Service Marginal Price (ASMP) Zones Day Ahead (IFM) and Hour Ahead/Real Time (HASP/RT) Ancillary Services total procurement costs divided by the CASIO control area system load. The data used to calculate the Ancillary Services rate is subject to change by the ISO without notice. Therefore, the Ancillary Service rate will be calculated using the best available data at the time of downloading.

The ISO GMC will equal the sum of the GMC – Market Services Charge (Charge Code 4560) and GMC – System Operations Charge (Charge Code 4561). The ISO GMC shall be charged on the customer's hourly metered demand.

2. Revised Hourly Market Price (N)

Pursuant to Decision 11-12-018 and Resolution E-4475, the revised hourly market price (Revised Hourly Market Price or Revised MP) will equal the sum of the Hourly Market Price, as determined in Part 1, the Renewable Portfolio Standard (RPS) adder and the Capacity adder (CAP ADDER). The RPS adder and CAP ADDER will be adjusted annually upon Commission approval in PG&E's Energy Resource Recovery Account (ERRA) Forecast proceeding.

Revised MP = MP + RPS adder + CAP ADDER

a. The RPS adder will be:

RPS adder = RPS% * [(0.68 * (URGgreen – BROWN)) + (0.32 * DOEadder)] (N)

(Continued)

RATES: (Cont'd.)

2. Revised Hourly Market Price (cont'd.) (N)

Where:

i. RPS% is equal to the fraction of RPS compliant electric energy in the Utility Retained Generation (URG) total portfolio for bundled service customers as defined in Resolution E-4475, and as approved in PG&E's most recent annual ERRA Forecast proceeding; and

ii. URGgreen is equal to the Commission approved average utility RPS-compliant energy cost, as defined in Resolution E-4475, and as approved in PG&E's most recent annual ERRA Forecast proceeding; and

iii. BROWN is equal to the Commission approved weighted average peak and off-peak forward prices for Northern Path 15 (NP15), as defined in Resolution E-4475, and as approved in PG&E's most recent annual ERRA Forecast proceeding; and

iv. DOEadder is as defined in Resolution E-4475, and as approved in PG&E's most recent annual ERRA Forecast proceeding.

b. The CAP ADDER is as defined in Resolution E-4475, and as approved in PG&E's most recent annual ERRA Forecast proceeding.

CAP ADDER = (ΣNQC * CAP Value) / URG Forecast Total Portfolio MWh for bundled customers

Where:

i. ΣNQC is equal to the sum of Net Qualifying Capacity (NQC) for all resources in the URG total portfolio for bundled customers; and,

ii. CAP VALUE is equal to the going forward cost (sum of insurance, ad valorem and fixed operations and maintenance cost) of a combustion turbine as determined per the most recent California Energy Commission (CEC) *Comparative Costs of California Central Station Electricity Generation Report* for a small simple cycle merchant plant; and,

iii. Total MWh is equal to the forecast of the sum of MWh supplied by URG total portfolio for bundled customers.

(N)

(Continued)

RATES: (Cont'd.)

3. Adjustments for DLFs and Revenue Fees and Uncollectible (RF&U) accounts expense: (T)

The Revised Hourly Market Price at the transmission/distribution interface, as determined in Part 2, is multiplied by the distribution loss factor (DLF) and a Revenue Fees and Uncollectible (RF&U) accounts expense factor to determine the appropriate price to be paid by end-use customers served at each voltage level (Hourly TBCC Price). DLFs will be calculated by PG&E based on the forecasted hourly PG&E Service Area Load (Direct Access, Community Choice Aggregation Service, plus Bundled Service) per Decisions 97-08-056 and 04-12-046. The hourly DLFs will be broken out by service voltage level and made available each day to market. PG&E will calculate the hourly DLFs based on samples of hourly service area load by applying the approach approved in Decisions 92-12-057, and 04-12-046. (T)

Hourly TBCC Price = Revised MP * DLF * RF&U (T)

The current and effective Revenue Fees and Uncollectible (RF&U) accounts expense can be found in the most recent PG&E General Rate Case Phase 1 proceeding documentation. (T)

ELECTRIC SCHEDULE TBCC Sheet 5
TRANSITIONAL BUNDLED COMMODITY COST

CALCULATION OF TBCC CHARGES:

1. Calculation of TBCC Charges: (L)

For purposes of determining TBCC charges, an average for each schedule (or TOU period) is developed through the use of a statistical load profile which represents the average load profile for all customers (Direct Access, Community Choice Aggregation, and Bundled Service) on a given rate schedule. For Agricultural, Traffic Control, Streetlighting, and Outdoor Lighting rate schedules, the statistical load profiles are "static" and are determined hourly for the entire year based on average historical data for three recorded years. These latter static statistical load profiles are updated each calendar year based on available data for the previous three years. For all remaining rate schedules, the statistical load profile is determined "dynamically," using the most current load research information available. This current data will become available and will be posted approximately seven days from the date of occurrence.

The sum of the products of the: (1) Hourly TBCC prices, including adjustments, and (2) the hourly loads, divided by the use associated with the statistical load profile (expressed as a fraction of the profile period use allocated to each hour) will yield an average price for a specific customer group and TOU period. (T)

Under static statistical load profiles, the load selected from the statistical load profile will correspond exactly to the date and hour for a given price. When dynamic statistical load profiles are used, the load selected from the statistical load profile will correspond exactly to the date and hour for a given price. Should dynamic load profile data for any days during the last week of the averaging period be unavailable, PG&E will duplicate the dynamic load profile for the same day(s) from the previous week for use in this calculation. These duplicate statistical load profile days will be replaced for the next weekly update by the dynamic load corresponding to the date and hour of the price, which will have become available. In other circumstances where dynamic load profile information is not available, an estimated static profile corresponding to the same date and hour will be substituted.

The customer's actual usage (by TOU period if service is otherwise taken on a TOU rate schedule) multiplied by the average TBCC price is equal to the TBCC charge. (L)

(Continued)

ELECTRIC SCHEDULE TBCC
TRANSITIONAL BUNDLED COMMODITY COST

CALCULATION OF TBCC CHARGES: (Cont'd.)

2. Revisions to Average TBCC Prices (L)

Average TBCC prices will be calculated on a weekly basis, effective on Thursday and utilized for all billing executed through the following week. In order to take the actual length of the billing period into consideration, prices spanning from 4 to 12 weeks will be calculated. For this purpose, a week is defined to be Saturday through Friday, with the last week in the span ending on the Friday prior to the TBCC price effective date. Billing periods that span 4 or fewer weeks shall use the 4-week average. Billing periods that span 12 or more weeks shall use the 12-week average.

Exception: In some instances at the beginning of the summer billing season, the 30-day record period will include fewer than three summer season billing days. In such cases, price data from up to the last three winter billing season weekdays (those lying closest to the start of the summer billing season) will be used in order to calculate proxy average TBCC prices for those TOU periods that are applicable only to summer season usage. Also, beginning approximately one month after the start of the winter billing season, the 30-day record period may not include enough summer season billing days to calculate average TBCC prices for summer-only TOU periods. In such instances, the last average TBCC prices that have been calculated for the summer-only TOU periods will be retained as proxies, for use as needed with usage information from subsequent record periods. (L)

(Continued)

ELECTRIC SCHEDULE TBCC
TRANSITIONAL BUNDLED COMMODITY COST

distribution loss factors: (L)

UDC Load MW	Primary LF	Secondary LF	UDC Load MW	Primary LF	Secondary LF
4300	N/A	N/A	**8700**	1.0190	1.0683
4400	N/A	N/A	**8800**	1.0192	1.0686
4500	N/A	N/A	**8900**	1.0193	1.0689
4600	1.0135	1.0659	**9000**	1.0195	1.0692
4700	1.0136	1.0655	**9100**	1.0197	1.0695
4800	1.0136	1.0651	**9200**	1.0198	1.0698
4900	1.0137	1.0649	**9300**	1.0200	1.0701
5000	1.0138	1.0646	**9400**	1.0202	1.0704
5100	1.0139	1.0644	**9500**	1.0203	1.0707
5200	1.0141	1.0642	**9600**	1.0205	1.0711
5300	1.0142	1.0640	**9700**	1.0206	1.0714
5400	1.0143	1.0639	**9800**	1.0208	1.0717
5500	1.0144	1.0638	**9900**	1.0210	1.0721
5600	1.0145	1.0637	**10000**	1.0211	1.0724
5700	1.0146	1.0636	**10100**	1.0213	1.0728
5800	1.0148	1.0636	**10200**	1.0215	1.0731
5900	1.0149	1.0635	**10300**	1.0216	1.0735
6000	1.0150	1.0635	**10400**	1.0218	1.0738
6100	1.0152	1.0635	**10500**	1.0220	1.0742
6200	1.0153	1.0636	**10600**	1.0221	1.0746
6300	1.0154	1.0636	**10700**	1.0223	1.0749
6400	1.0156	1.0637	**10800**	1.0225	1.0753
6500	1.0157	1.0638	**10900**	1.0226	1.0757
6600	1.0158	1.0639	**11000**	1.0228	1.0761
6700	1.0160	1.0640	**11100**	1.0230	1.0764
6800	1.0161	1.0641	**11200**	1.0231	1.0768
6900	1.0163	1.0642	**11300**	1.0233	1.0772
7000	1.0164	1.0644	**11400**	1.0235	1.0776
7100	1.0166	1.0645	**11500**	1.0236	1.0780
7200	1.0167	1.0647	**11600**	1.0238	1.0784
7300	1.0168	1.0649	**11700**	1.0240	1.0788
7400	1.0170	1.0651	**11800**	1.0241	1.0792
7500	1.0172	1.0653	**11900**	1.0243	1.0796
7600	1.0173	1.0655	**12000**	1.0245	1.0800
7700	1.0175	1.0657	**12100**	1.0246	1.0803
7800	1.0176	1.0659	**12200**	1.0248	1.0807
7900	1.0178	1.0662	**12300**	1.0250	1.0811
8000	1.0179	1.0664	**12400**	1.0251	1.0816
8100	1.0181	1.0666	**12500**	1.0253	1.0820
8200	1.0182	1.0669	**12600**	1.0255	1.0823
8300	1.0184	1.0672	**12700**	1.0256	1.0827
8400	1.0186	1.0674	**12800**	1.0258	1.0831
8500	1.0187	1.0677	**12900**	1.0259	1.0835
8600	1.0189	1.0680	**13000**	1.0262	1.0841
			13100	1.0263	1.0844
			13200	1.0265	1.0848

(L)

(Continued)

ELECTRIC SCHEDULE TBCC
TRANSITIONAL BUNDLED COMMODITY COST

distribution loss factors: (Cont'd.)

UDC Load MW	Primary LF	Secondary LF	UDC Load MW	Primary LF	Secondary LF	
						(L)
13300	1.0267	1.0853	**15100**	1.0298	1.0932	|
13400	1.0268	1.0857	**15200**	1.0300	1.0936	|
13500	1.0270	1.0861	**15300**	1.0301	1.0941	|
13600	1.0271	1.0865	**15400**	1.0303	1.0945	|
13700	1.0274	1.0870	**15500**	1.0305	1.0949	|
13800	1.0275	1.0875	**15600**	1.0306	1.0954	|
13900	1.0277	1.0878	**15700**	1.0308	1.0958	|
14000	1.0278	1.0882	**15800**	1.0310	1.0962	|
14100	1.0280	1.0887	**15900**	1.0312	1.0967	|
14200	1.0281	1.0890	**16000**	1.0313	1.0971	|
14300	1.0283	1.0895	**16100**	1.0315	1.0975	|
14400	1.0286	1.0901	**16200**	1.0317	1.0980	|
14500	1.0287	1.0906	**16300**	1.0318	1.0984	|
14600	1.0289	1.0910	**16400**	1.0320	1.0988	|
14700	1.0291	1.0914	**16500**	1.0322	1.0992	|
14800	1.0293	1.0919	**16600**	1.0323	1.0997	|
14900	1.0294	1.0923	**16700**	1.0325	1.1001	|
15000	1.0296	1.0928	**16800**	1.0327	1.1005	|
			16900	1.0329	1.1010	|
			17000	1.0330	1.1014	(L)