APPENDIX B

ENERGY PAYMENT OPTIONS

Energy Payment Option 1 - Forecasted Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during each year of the <u>fixed price period</u> shall include the appropriate prices for such year in Table B-1, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the forecasted off-peak hours' energy prices listed in Table B-1 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B.

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TABLE B-1

Forecasted Energy Price Schedule

Year of Energy Deliv-eries	Forecasted Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.16
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 2 - Levelized Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the fixed price period shall include the appropriate prices set forth in Table B-2 for the year in which energy deliveries begin and term of agreement, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the levelized off-peak hours' energy prices listed in Table B-2 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B. The discount specified in (c)(vi) below, if applicable, will be applied to the energy payments during the fixed price period.

During the fixed price period, Seller shall be subject to the following conditions and terms:

(a) Minimum Damages

The Parties agree that the levelized energy prices which PGandE pays Seller for the energy which Seller delivers to PGandE is based on the agreed value to PGandE of Seller's energy deliveries during the entire fixed price period. In the event PGandE does not receive such full performance by reason of a termination, Seller shall pay PGandE an amount based on the difference between the net present values, at the time of termination, of the payments Seller would receive at the forecasted energy prices in Table B-1 and the payments Seller would receive at the levelized energy prices, for the remaining years of the fixed price period. This amount shall be calculated by assuming that Seller continued to generate for the remaining years of the fixed price period at a level equal to the average annual energy generation during the period of performance, and by applying the weighted annual average levelized price applicable to Seller's Facility and the weighted annual average forecasted energy prices in Table B-1 for the remaining years of the fixed price period. The following formula shall be used to make this calculation:

$$P = \sum_{n=1}^{Y} \frac{(F_n)(A)(W)}{(1.15)^n} - \sum_{n=1}^{Y} \frac{(L)(A)(W)}{(1.15)^n}$$

where:

P = amount due PGandE.

Y = number of years remaining in the fixed price period.

F_n = weighted annual average forecasted energy price in the n^{th} year after the breach, failure to perform, or expiration of security, as shown in Table B-1 for the corresponding calendar year.

L = weighted annual average levelized energy price applicable to Seller's <u>Facility</u>.

A = average annual energy generation by Seller during the period of performance.

n = summation index; refers to the $n^{\underline{th}}$ year following termination.

W = percent of Seller's energy payments based on the levelized energy prices, as specified in Article 4.

(b) Performance Requirements

Seller shall operate and maintain the <u>Facility</u> in accordance with <u>prudent electrical practices</u> in order to maximize the likelihood that the <u>Facility's</u> output as delivered to PGandE during the part of the <u>fixed price period</u> when the levelized price is below the forecasted price ("last part") shall equal or exceed 70% of the <u>Facility's</u> output during the part of the <u>fixed price period</u> when the levelized price is above the forecasted price ("first part"). In the event that the <u>Facility's</u> output during any year or series of years in the last part of the <u>fixed price period</u> is less than 70% of the average annual production during the first part of the <u>fixed price period</u>, PGandE may, at its discretion (taking into consideration events occurring during such year or series of years such as curtailment by PGandE, Seller's choice not to operate during adjusted price periods, or scheduled maintenance including major overhauls, and the probability that Seller's future performance will be adequate), either request payment from Seller or immediately draw on the security posted, up to the amount equal to $P \times \frac{A-B}{A}$, where:

P and A are as defined in Section (a) above.

B = Seller's average annual energy generation during the year or series of years in which the 70% performance requirement was not met.

PGandE shall not request payment from Seller or draw on the security posted if the <u>Facility's</u> output during the last part of the <u>fixed price period</u> falls below 70% of the average annual energy generation during the first part of the <u>fixed price period</u> solely because of force majeure as defined in Section A-8, Appendix A or a lack of or limited availability of the primary energy resource of the <u>Facility</u>, if such energy resource is wind, water, or sunlight.

(c) Security

(1) As security for amounts which Seller may be obligated to pay PGandE pursuant to Sections (a) and (b) above, Seller shall provide and maintain one or more of the following in an amount as

described in Section (c)(2) below.

(i) An irrevocable bank letter of credit delivered to and in favor of PGandE with terms acceptable to PGandE.

(ii) A payment bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(iii) Fully paid up, noncancellable Project Failure Insurance made payable to PGandE with terms of such policy(ies) acceptable to PGandE.

(iv) A performance bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(v) A corporate guarantee of payment to PGandE which PGandE deems, in its sole discretion, to provide at least the same quality of security as subsections (i) through (iv) above.

(vi) Other forms of security which PGandE does not deem to be equivalent security to those listed in subsections (i) through (v) above, and which PGandE, in its sole discretion, deems adequate. Such other forms of security may include, for example, a corporate guarantee or a lien, mortgage or deed of trust on the Facility or land upon which it is located. A 1.5% discount will be applied against the levelized energy price portion of PGandE's payments to Seller during the fixed price period if this type of security is provided.

(2) (i) Commencing 90 days prior to the scheduled operation date and continuing until December 1 of the following calendar year, security as described in Section (c)(1) above shall be in place in an amount calculated in accordance with the formula set forth in Section (a) above, assuming Seller delivered energy through the end of the following calendar year and then terminated this Agreement. For purposes of determining the

required amount of security, it shall be assumed that Seller's deliveries through the end of the following calendar year would equal R x C x H, where:

R = nameplate rating, in kW, of the Facility.

C = estimated capacity factor of the Facility, which shall be established by mutual agreement of the Parties at the time of execution of this Agreement.

H = number of hours from the scheduled operation date through the end of the following calendar year.

(ii) In the second calendar year of operation and each year thereafter until the end of the fixed price period, from December 1 through December 1 of the following year, security shall be in place in an amount calculated by the formula set forth in Section (a) above assuming Seller continued to deliver energy in each month through the end of the following calendar year, at a level equal to the average monthly energy deliveries to date, and then terminated this Agreement.

(3) Security must be maintained throughout the fixed price period as specified above. Any security with a fixed expiration date must be renewed by Seller prior to that date. If such security is not renewed at least 30 days prior to its expiration, PGandE may, at its discretion, either request payment from Seller or immediately draw on the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above.

(4) If, at any time during the fixed price period, PGandE believes Seller is in material breach of this Agreement, PGandE shall so notify Seller in writing and Seller must remedy such breach within a reasonable period of time. If Seller does not so remedy, PGandE may, at its discretion, either request payment from Seller or immediately draw upon the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above, provided that if during Seller's period to remedy, Seller disputes PGandE's conclusion that Seller is in material breach, and PGandE elects to draw upon the security, the amount drawn upon by PGandE shall be deposited in an interest earning escrow account and held in such account until the dispute is resolved in accordance with Section (c)(5) below.

(5) Upon the written request of either Party, any controversy or dispute between the Parties concerning Section (c)(4) above shall be subject to arbitration in accordance with the provisions of the California Arbitration Act, Sections 1280-1294.2 of the California Code of Civil Procedure except as provided otherwise in this section. Either Party may demand arbitration by first giving written notice of the existence of a dispute and then within 30 days of such notice giving a second written notice of the demand for arbitration.

Within ten days after receipt of the demand for arbitration, each Party shall appoint one person, who shall not be an employee of either Party, to hear and determine the dispute. After both arbitrators have been appointed, they shall within five (5) days select a third arbitrator.

The arbitration hearing shall take place in San Francisco, California, within 30 days of the appointment of the arbitrators, at such time and place as they select. The arbitrators shall give written notice of the time of the hearing to both Parties at least ten days prior to the hearing. The arbitrators shall not be authorized to alter, extend, or modify the terms of this Agreement. At the hearing, each Party shall submit a proposed written decision, and any relevant evidence may be presented. The decision of the arbitrators must consist of selection of one of the two proposed decisions, in its entirety.

The decision of any two arbitrators shall be binding and conclusive as to disputes relating to Section (c)(4) only. Upon determining the matter, the arbitrators shall promptly execute and acknowledge their decision and deliver a copy to each Party. A judgment confirming the award may be rendered by any superior court having jurisdiction. Each Party shall bear its own arbitration costs and expenses, including the cost of the arbitrator it selected, and the costs and expenses of the third arbitrator shall be divided equally between both Parties, except as provided otherwise elsewhere in this Agreement.

Pending resolution of any controversy or dispute hereunder, performance by each Party shall continue so as to maintain the status quo prior to notice of such controversy or dispute. Resolution of the controversy or dispute shall include payment of any interest accrued in the escrow account.

TABLE B-2
Levelized Energy Price Schedule

For a term of agreement of 15-16 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.76	5.50	5.31	5.85	5.71	5.58	5.57
1984	6.06	5.78	5.58	6.14	6.00	5.86	5.85
1985	6.41	6.11	5.91	6.50	6.35	6.20	6.19
1986	6.85	6.54	6.32	6.95	6.79	6.63	6.62
1987	7.37	7.03	6.79	7.47	7.30	7.13	7.12
1988	7.96	7.60	7.34	8.07	7.89	7.70	7.69

For a term of agreement of 17-19 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.90	5.63	5.44	5.98	5.84	5.71	5.70
1984	6.23	5.95	5.74	6.32	6.18	6.03	6.02
1985	6.60	6.30	6.08	6.69	6.53	6.38	6.37
1986	7.06	6.73	6.51	7.16	7.00	6.83	6.82
1987	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1988	8.21	7.83	7.57	8.32	8.13	7.94	7.93

For a term of agreement of 20-30 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	6.49	6.20	5.98	6.58	6.43	6.28	6.27
1984	6.90	6.58	6.35	6.99	6.83	6.67	6.66
1985	7.34	7.00	6.76	7.44	7.27	7.10	7.09
1986	7.88	7.51	7.26	7.99	7.81	7.62	7.61
1987	8.49	8.10	7.82	8.61	8.41	8.21	8.20
1988	9.16	8.74	8.44	9.29	9.08	8.86	8.85

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 3 - Incremental Energy Rate

During the period specified in **Article 4**, annual adjustments to Seller's energy payments shall be made as described below.

At the end of each calendar year, the Derived Incremental Energy Rate (with units expressed in Btu/kWh) will be calculated as follows:

$$\text{Derived Incremental Energy Rate (DIER)} = \frac{B}{A \times C}$$

where:

A = the total kWh delivered by Seller during the calendar year, excluding any kWh delivered when Seller was asked to curtail deliveries under Curtailment Option A or when Seller was asked to take adjusted prices under Curtailment Option B.

B = the total dollars paid for the energy described for A above.

C = the weighted average price paid during the calendar year by PGandE's Electric Department for oil and natural gas for PGandE's fossil steam plants, expressed in \$/Btu on a gas Btu basis.

If the DIER is between the upper and lower Incremental Energy Rate Bounds specified for that year in Table B-3 for the curtailment option selected by Seller, no additional payment is due either Party.

If the DIER is below the lower Incremental Energy Rate Bound, PGandE shall pay Seller an amount calculated as follows:

$$P_S = \left(\begin{matrix}\text{Lower Incremental}\\ \text{Energy Rate Bound}\end{matrix} - \text{DIER}\right)(A)(C)$$

where:

P_S = additional payment due Seller.

DIER = Derived Incremental Energy Rate.

PGandE shall add this payment to the first payment made to Seller following the calculation.

If the DIER is above the upper Incremental Energy Rate Bound, Seller shall pay PGandE an amount calculated as follows:

$$P_B = \left(\text{DIER} - \begin{matrix}\text{Upper Incremental}\\ \text{Energy Rate Bound}\end{matrix}\right)(A)(C)$$

where:

P_B = amount due PGandE.

DIER = Derived Incremental Energy Rate.

This amount shall be deducted from the first payment made to Seller following the calculation. If there is any remaining amount due PGandE, PGandE may, at its option, invoice Seller with such payment due within 30 days or deduct this amount from future payments due Seller.

TABLE B-3

Forecasted Incremental Energy Rates and
Incremental Energy Rate Bounds

Curtailment Option A:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]
1984	9,000	______	______	______
1985	9,050	______	______	______
1986	8,840	______	______	______
1987	8,850	______	______	______
1988	8,960	______	______	______
1989	8,820	______	______	______
1990	8,540	______	______	______
1991	8,540	______	______	______
1992	8,540	______	______	______
1993	8,540	______	______	______
1994	8,540	______	______	______
1995	8,540	______	______	______
1996	8,540	______	______	______
1997	8,540	______	______	______
1998	8,540	______	______	______

TABLE B-3 (continued)

Curtailment Option B:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]
1984	9,440	______	______	______
1985	9,500	______	______	______
1986	9,280	______	______	______
1987	9,290	______	______	______
1988	9,400	______	______	______
1989	9,270	______	______	______
1990	8,970	______	______	______
1991	8,970	______	______	______
1992	8,970	______	______	______
1993	8,970	______	______	______
1994	8,970	______	______	______
1995	8,970	______	______	______
1996	8,970	______	______	______
1997	8,970	______	______	______
1998	8,970	______	______	______

TABLE B-4[1]
Time Periods

	Monday through Friday[2]	Saturdays[2]	Sundays and Holidays
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

1 This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

2 Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

TABLE B-5

ENERGY PRICES

Energy Prices Effective November 1, 1984 - January 31, 1985

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during November, December, and January are as follows:

Time Period	(a) Incremental Energy Rate[1] (Btu/kWh)	(b) Cost of Energy[2] ($/$10^6$ Btu)	(c) Revenue Requirement for Cash Working Capital[3] ($/kWh)	(d) Energy Purchase Price[4] (d) = [(a) x (b)] + (c) ($/kWh)
November 1 - January 31 (Period B)				
Time of Delivery Basis:				
On-Peak	16,320	5.4011	0.00053	0.08868
Partial-Peak	15,689	5.4011	0.00051	0.08525
Off-Peak	11,625	5.4011	0.00038	0.06317
Seasonal Average (Period B)	13,692	5.4011	0.00045	0.07440

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1 Incremental energy rates (Btu/kWh) for Seasonal Period A and Seasonal Period B are derived from the marginal energy costs (including variable operating and maintenance expense) adopted by the CPUC in Decision No. 83-12-068 (page 339). They are based upon natural gas as the incremental fuel and weighted average hydroelectric power conditions.

2 Cost of natural gas under PGandE Gas Schedule No. G-55 effective October 1, 1984 per Advice No. 1285-G.

3 Revenue Requirement for Cash Working Capital as prescribed by the CPUC in Decision No. 83-12-068.

4 Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of CPUC Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table B-6.

TABLE B-6

Energy Loss Adjustment Factors[1]

	Transmission	Primary Distribution	Secondary Distribution
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

1 The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

APPENDIX C

CURTAILMENT OPTIONS

Seller has two options regarding curtailment of energy deliveries and Seller has made its selection in Article 7. The two options are as follows:

CURTAILMENT OPTION A - HYDRO SPILL AND NEGATIVE AVOIDED COST

(a) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF - S}{AQF} \times PP \qquad (\geq 0)$$

where:

AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period.

(b) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy during periods when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

(c) Before interrupting or reducing deliveries under subsection (b), above, and before invoking hydro savings prices under subsection (a), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.

(d) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (a) or when PGandE curtails deliveries of energy pursuant to subsection (b), Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (a) or (b) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

CURTAILMENT OPTION B - ADJUSTED PRICE PERIOD

(a) In each calendar year, the price which PGandE is obligated to pay Seller for energy deliveries during 1,000 off-peak hours (as defined in Table B-4, Appendix B) may be adjusted to a price equal to, but not in excess of, PGandE's available alternative source. This adjusted price shall be effective under any of the following conditions:

(i) when PGandE's energy source at the margin is not a PGandE oil- or gas-fueled plant, and PGandE can replace Seller's energy with energy from this source at a cost less than the price paid to Seller;

(ii) when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement; or

(iii) when PGandE is experiencing minimum system operations.

During any of the conditions described above the adjusted price may be zero.

(b) Whenever possible, PGandE shall give Seller reasonable notice of any price adjustment for energy deliveries and its probable duration.

(c) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the adjusted price, Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE.

(d) After Seller receives notice of the probable duration of the period during which the adjusted price will be paid, Seller may elect to perform maintenance during such period and so inform the PGandE employee in charge at the <u>designated</u> <u>PGandE</u> <u>switching</u> <u>center</u> prior to the time when the adjusted price period is expected to begin. If Seller makes such election, the number of off-peak hours of probable duration quoted in PGandE's notice to Seller shall be applied to the 1,000-hour calendar year limitation set forth in this section. After an election to do maintenance, if Seller makes any deliveries of energy during the quoted probable duration period, Seller shall be paid the adjusted price quoted in its notice from PGandE without regard to any subsequent changes on the PGandE system which may alter the adjusted price or shorten the actual duration of the condition.

APPENDIX D

AS-DELIVERED CAPACITY

D-1 AS-DELIVERED CAPACITY PAYMENT OPTIONS

Seller has two options for as-delivered capacity payments and Seller has made its selection in Article 5. The two options are as follows:

AS-DELIVERED CAPACITY PAYMENT OPTION 1

PGandE shall pay Seller for as-delivered capacity at prices authorized from time to time by the CPUC. The as-delivered capacity prices in effect on the date of execution are calculated as shown in Exhibit D-1.

AS-DELIVERED CAPACITY PAYMENT OPTION 2

During the fixed price period, the as-delivered capacity prices will be calculated in accordance with Exhibit D-1 and the forecasted shortage costs in Table D-2.

For the remaining years of the term of agreement, PGandE shall pay Seller for as-delivered capacity at the higher of:

(i) prices authorized from time to time by the CPUC;

(ii) the as-delivered capacity prices that were paid Seller in the last year of the fixed price period; or

(iii) the as-delivered capacity prices in effect in the first year following the end of the fixed price period, provided that the annualized shortage cost from which these prices are derived does not exceed the annualized value of a gas turbine.

D-2 AS-DELIVERED CAPACITY IN EXCESS OF FIRM CAPACITY

The amount of capacity delivered in excess of firm capacity will be considered as-delivered capacity. This as-delivered capacity is based on the total kilowatt-hours delivered each month during all on-peak, partial-peak and off-peak hours excluding any energy associated with generation levels equal to or less than the firm capacity.

Seller has the two options listed in Section D-1 for payment for such as-delivered capacity. Seller has made its selection in Article 5.

EXHIBIT D-1

The as-delivered capacity price (in cents per kW-hr) for power delivered by the Facility is the product of three factors:

(a) The shortage cost in each year the Facility is operating. Currently, this shortage cost is $156 per kW-year.

(b) A capacity loss adjustment factor which provides for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote[1] Facilities are presented in Table D-1(a). Capacity loss adjustment factors for remote Facilities shall be calculated individually.

(c) An allocation factor which accounts for the different values of as-delivered capacity in different time periods and converts dollars per kW-year to cents per kWh. The current allocation factors are presented in Table D-1(b). The time periods to which they apply are shown in Table B-4, Appendix B. The allocation factors are subject to change from time to time.

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[1] As defined by the CPUC.

TABLE D-1(a)

Capacity Loss Adjustment Factors
for Non-Remote[1] Facilities

Voltage Level	Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote, the capacity loss adjustment factor is ______________[2].

TABLE D-1(b)

Allocation Factors
for As-Delivered Capacity[3]

	On-Peak (¢-yr/$-hr)	Partial-Peak (¢-yr/$-hr)	Off-Peak (¢-yr/$-hr)
Seasonal Period A	.10835	.02055	.00002
Seasonal Period B	.00896	.00109	.00001

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1 As defined by the CPUC. The capacity loss adjustment factors for remote Facilities are determined individually.

2 Determined individually.

3 The units for the allocation factor, ¢-yr/$-hr, are derived from the conversion of $/kW-yr into ¢/kWh as follows:

$$\frac{¢/\text{kWh}}{\$/\text{kW-yr}} = \frac{¢/\text{kW-hr}}{\$/\text{kW-yr}} = \frac{¢\text{-yr}}{\$\text{-hr}}$$

The allocation factors were prescribed by the CPUC in Decision No. 83-12-068 and are subject to change from time to time.

TABLE D-2

Forecasted Shortage Cost Schedule

Year	Forecast Shortage Cost, $/kW-Yr
1983	70
1984	76
1985	81
1986	88
1987	95
1988	102
1989	110
1990	118
1991	126
1992	135
1993	144
1994	154
1995	164
1996	176
1997	188

APPENDIX E

FIRM CAPACITY

CONTENTS

APPENDIX E

FIRM CAPACITY

E-1 GENERAL

This Appendix E establishes conditions and prices under which PGandE shall pay for firm capacity.

PGandE's obligation to pay for firm capacity shall begin on the firm capacity availability date. The firm capacity price shall be subject to adjustment as provided for in this Appendix E.

The firm capacity prices in Table E-2 are applicable for deliveries of firm capacity beginning after December 30, 1982.

E-2 PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments, the firm capacity shall be delivered for all of the on-peak hours[1] in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for forced outages in any month. Compliance with this provision shall be based on the Facility's total on-peak deliveries for each of the peak

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[1] On-peak, partial-peak, and off-peak hours are defined in Table B-4, Appendix B.

months and shall exclude any energy associated with generation levels greater than the firm capacity.

(b) If Seller is prevented from meeting the performance requirements because of a forced outage on the PGandE system, a PGandE curtailment of Seller's deliveries, or a condition set forth in Section A-7, Appendix A, PGandE shall continue capacity payments. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevented from meeting the performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereafter, Seller shall be deemed to have failed to have met the performance requirements. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the performance requirements because of exteme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish firm capacity pursuant to Section E-8. Seller shall warrant to PGandE that the Facility is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its firm capacity obligations.

(e) If Seller is prevented from meeting the performance requirements for reasons other than those described above in Sections E-2(b), (c), or (d):

(1) Seller shall receive the reduced <u>firm capacity</u> payments as provided in Section E-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.

(2) If, at the end of the probationary period Seller has not demonstrated that the <u>Facility</u> can meet the performance requirements, PGandE may derate the <u>firm capacity</u> pursuant to Section E-4(b).

E-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 9, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

If Seller has selected Curtailment Option B, off-peak hours of maintenance performed pursuant to Section (d) of Curtailment Option B, Appendix C shall not be deducted from Seller's scheduled maintenance allowances set forth above.

E-4 ADJUSTMENTS TO FIRM CAPACITY

(a) Seller may increase the <u>firm capacity</u> with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.

(b) Seller may reduce the <u>firm capacity</u> at any time prior to the <u>firm capacity availability date</u> by giving written notice thereof to PGandE. PGandE may derate the <u>firm capacity</u> in accordance with Section E-2(e) as a result of appropriate data showing Seller has failed to meet the performance requirements of Section E-2.

E-5 FIRM CAPACITY PAYMENTS

The method for calculation of firm capacity payments is shown below. As used below in this section, month refers to a calendar month.

The monthly payment for firm capacity will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table E-1 based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table E-3, plus any allowable payment for outages due to scheduled maintenance. The firm capacity price shall be applied to meter readings taken during the separate times and periods as illustrated in Table B-4, Appendix B.

The PPF is determined by multiplying the firm capacity price by the following Allocation Factors[1]:

	Allocation Factor	x	Firm Capacity Price	=	PPF ($/kW-month)
Seasonal Period A	.18540		____________		____________
Seasonal Period B	.01043		____________		____________

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1 These allocation factors were prescribed by the CPUC in Decision No. 83-12-068. All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the CPUC. Seasonal Periods A and B are defined in Table B-4, Appendix B.

The MDC is determined in the following manner:

(1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B-S) \times (0.8^*)} \qquad (\leq 1.0)$$

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the firm capacity.

C = Firm capacity in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month Facility is out of service on scheduled maintenance.

(2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month Facility is out of service on scheduled maintenance.

D = The number of hours in the month.

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* 0.8 reflects a 20% allowance for forced outage.

(3) Determine the MDC by multiplying the MCF by C:

$$\text{MDC (kilowatts)} = \text{MCF} \times \text{C}$$

The monthly payment for <u>firm capacity</u> is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table E-1, and by the appropriate performance bonus factor, if any, from Table E-3.

$$\text{monthly payment for } \underline{\text{firm}}\ \underline{\text{capacity}} = \text{PPF} \times \text{MDC} \times \text{capacity loss adjustment factor} \times \text{performance bonus factor}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly <u>firm</u> <u>capacity</u> payment[1] for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. <u>Firm</u> <u>capacity</u> payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section E-3 are met.

During a probationary period Seller's monthly payment for <u>firm</u> <u>capacity</u> shall be determined by substituting for the <u>firm</u> <u>capacity</u>, the capacity at which

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[1] Total monthly payment divided by the total number of hours in the monthly billing period.

Seller would have met the performance requirements. In the event that during the probationary period Seller does not meet the performance requirements at whatever firm capacity was established for the previous month, Seller's monthly payment for firm capacity shall be determined by substituting the firm capacity at which Seller would have met the performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE E-1

If the Facility is non-remote[1] the firm capacity loss adjustment factors are as follows:

Voltage Level	Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote the firm capacity loss adjustment factor is ______________[2].

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1 As defined by the CPUC.

2 Determined individually.

TABLE E-2

Firm Capacity Price Schedule

(Levelized $/kW-year)

Firm Capacity Availability Date (Year)	Number of Years of Firm Capacity Delivery: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1982	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

TABLE E-3

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for firm capacity delivered by the Facility after it has demonstrated a firm capacity factor in excess of 85%.

DEMONSTRATED FIRM CAPACITY FACTOR (%)	PERFORMANCE BONUS FACTOR
85	1.000
90	1.059
95	1.118
100	1.176

After the Facility has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

(i) the firm capacity factor for each such month shall be calculated in the following manner:

$$\text{FIRM CAPACITY FACTOR (\%)} = \frac{F}{(N-W) \times Q} \times 100$$

Where:

F = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the firm capacity.

N = Total on-peak hours during the month.

W = Total on-peak hours during the peak month that the <u>Facility</u> is out of service on scheduled maintenance.

Q = <u>Firm</u> <u>capacity</u> in kilowatts.

(ii) the arithmetic average of the above <u>firm</u> <u>capacity</u> factors shall be determined for that span,

(iii) the average of the above arithmetic average <u>firm</u> <u>capacity</u> factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Firm Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Firm Capacity Factor not shown in Table E-3 use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Firm Capacity Factor (\%)}}{85\%}$$

<u>SECTIONS E-6 THROUGH E-10 SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS</u>

E-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section E-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

E-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section E-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to --

(1) Release requirements for support of fish life and any other operating constraints imposed on the project;

(2) Operating characteristics of the proposed equipment of the Facility such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;

(3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc.; and

(4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the Facility has water storage characteristics. For the study to show monthly capacity ratings, the Facility shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

E-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section E-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The <u>firm</u> <u>capacity</u> shown in Article 5 shall not exceed the lowest average dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July, and August.

E-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

(1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table E-4;

(2) A topographic project map which shows the location of all aspects of the <u>Facility</u> and locations of stream gauging stations used to determine natural flow data;

(3) A discussion of all major factors relevant to project operation;

(4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section E-6 and are consistent with generally accepted engineering practices; and

(5) Upon specific written request by PGandE, Seller's theoretical operation study.

E-10 ILLUSTRATIVE EXAMPLE

(1) Determine natural flows - These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".

(2) Perform theoretical operation study - Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This study is performed based on the <u>Facility's</u> design, operating capabilities, constraints, etc., and should take into account all factors relevant to project

operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.

(3) Determine average dry year capacity ratings - After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The <u>firm capacity</u> is then set by the Seller based on the monthly average dry year capacity ratings and the performance requirements of this appendix. An example project is shown in the attached completed Table E-4.

EXAMPLE
TABLE E-4

Summary of Theoretical Operation Study

Project: New Creek 1

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics[1]:

	Flow (cfs)	Head (feet) Gross	Head (feet) Net	Output (kW)	Efficiency (%) Turbine	Efficiency (%) Generator
Normal Operation	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation - Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum firm capacity: 410 kW

[1] If Facility has a variable head, operating curves should be provided.

E-11 MINIMUM DAMAGES

(a) In the event the <u>firm capacity</u> is derated or Seller terminates this Agreement, the quantity by which the <u>firm capacity</u> is derated or the <u>firm capacity</u> shall be used to calculate the payments due PGandE in accordance with Section (d).

(b) Seller shall be invoiced by PGandE for all amounts due under this section. Payment shall be due within 30 days of the date of invoice.

(c) If Seller does not make payments pursuant to Section (b), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.

(d) Seller shall pay to PGandE:

(i) an amount equal to the difference between (a) the <u>firm capacity</u> payments already paid by PGandE, based on the original <u>term of agreement</u> and (b) the total <u>firm capacity</u> payments which PGandE would have paid based on the period of Seller's actual performance using the <u>adjusted firm capacity price</u>. Additionally, Seller shall pay interest, compounded monthly from the date the excess capacity payment was made until the date

Seller repays PGandE, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate; plus

(ii) a sum equal to the amount by which the firm capacity is being terminated or derated times the difference between the current firm capacity price on the date of termination or deration for a term equal to the balance of the term of agreement and the firm capacity price, multiplied by the appropriate factor shown in Table E-5 below. In the event that the current firm capacity price is less than the firm capacity price, no payment under this subsection (ii) shall be due either Party.

TABLE E-5

Amount of Firm Capacity Terminated or Derated	Factor
1,000 kW or under	0.25
over 1,000 kW through 10,000 kW	0.75
over 10,000 kW through 25,000 kW	1.00
over 25,000 kW through 50,000 kW	3.00
over 50,000 kW through 100,000 kW	4.00
over 100,000 kW	5.00

APPENDIX F

INTERCONNECTION

CONTENTS

F-1 INTERCONNECTION TARIFFS

The applicable tariff follows on the succeeding pages.

F-2 POINT OF DELIVERY LOCATION SKETCH

The Seller requests, and PGandE consents, that the location sketch not be made at the time of executing the Agreement because the Seller, recognizing that the information is not yet available to make a definitive determination of the sketch to be inserted here, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the sketch to be inserted.

F-3 INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE

The Seller requests, and PGandE consents, that this listing of facilities not be filled in at the time of executing the Agreement because the Seller, recognizing that the information is not yet available to make a definitive determination of the listing of facilities to be inserted here, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the listing of facilities to be inserted.

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION

This describes the minimum operation, metering and interconnection requirements for any generating source or sources paralleled with the Utility's electric system. Such source or sources may include, but are not limited to, hydroelectric generators, wind-turbine generators, steam or gas driven turbine generators and photovoltaic systems.

A. GENERAL

1. The type of interconnection and voltage available at any location and the Utility's specific interconnection requirements shall be determined by inquiry at the Utility's local office.

2. The Utility's distribution and transmission lines which are an integral part of its overall system are distinguished by the voltages at which they are operated. Distribution lines are operated at voltages below 60 kv and transmission lines are operated at voltages 60 kv and higher.

3. The Power Producer (Producer) shall ascertain and be responsible for compliance with the requirements of all governmental authorities having jurisdiction.

4. The Producer shall sign the Utility's written form of power purchase agreement or parallel operation agreement before connecting or operating a generating source in parallel with the Utility's system.

5. The Producer shall be fully responsible for the costs of designing, installing, owning, operating and maintaining all interconnection facilities defined in Section B.1.

6. The Producer shall submit to the Utility, for the Utility's review and written acceptance, equipment specifications and detailed plans for the installation of all interconnection facilities to be furnished by the Producer prior to their purchase or installation. The Utility's review and written acceptance of the Producer's equipment specifications and detailed plans shall not be construed as confirming or endorsing the Producer's design or as warranting the equipment's safety, durability or reliability. The Utility shall not, by reason of such review or lack of review, be responsible for strength, details of design adequacy, or capacity of equipment built pursuant to such specifications, nor shall the Utility acceptance be deemed an endorsement of any such equipment.

7. No generating source shall be operated in parallel with the Utility's system until the interconnection facilities have been inspected by the Utility and the Utility has provided written approval to the Producer.

8. Only duly authorized employees of the Utility are allowed to connect Producer-installed interconnection facilities to, or disconnect the same from, the Utility's overhead or underground lines.

B. INTERCONNECTION FACILITIES

1. GENERAL: Interconnection facilities are all means required, and apparatus installed, to interconnect the Producer's generation with the Utility's system. Where the Producer desires to sell power to the Utility, interconnection facilities are also all means required, and apparatus installed, to enable the Utility to receive power deliveries from the Producer. Interconnection facilities may include, but are not limited to:
   a. connection, transformation, switching, metering, communications, control, protective and safety equipment; and
   b. any necessary additions to and reinforcements of the Utility's system by the Utility.

2. METERING
   a. A Producer desiring to sell power to the Utility shall provide, install, own and maintain all facilities necessary to accommodate metering equipment specified by the Utility. Such metering equipment may include meters, telemetering (applicable where deliveries to the Utility exceed 10 MW) and other recording and communications devices as may be required for the reporting of power delivery data to the Utility. Except as provided for in Section B.2.b following, the Utility shall provide, install, own and maintain all metering equipment as special facilities in accordance with Section F.

(Continued)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

B. INTERCONNECTION FACILITIES (continued)

2. METERING

b. The Producer may at its option provide, install, own and maintain current and potential transformers rated above 600 volts and a non-revenue type graphic recorder where applicable. Such metering equipment, its installation and maintenance shall all be in conformance with the Utility's specifications.

c. The Utility's meters shall be equipped with detents to prevent reverse registration so that power deliveries to and from the Producer's equipment can be separately recorded.

3. CONTROL, PROTECTION AND SAFETY EQUIPMENT

a. GENERAL: The Utility has established functional requirements essential for safe and reliable parallel operation of the Producer's generation. These requirements provide for control, protective and safety equipment to:
(1) sense and properly react to failure and malfunction on the Utility's system;
(2) assist the Utility in maintaining its system integrity and reliability; and
(3) protect the safety of the public and the Utility's personnel.

b. Listed below are the various devices and features generally required by the Utility as a prerequisite to parallel operation of the Producer's generation:

CONTROL, PROTECTION AND SAFETY EQUIPMENT GENERAL REQUIREMENTS[1]

	GENERATOR SIZE					
Device or Feature	10 kw or Less	11 kw to 40 kw	41 kw to 100 kw	101 kw to 400 kw	401 kw to 1,000 kw	Over 1,000 kw
Dedicated Transformer[2]	-	X	X	X	X	X
Interconnection Disconnect Device	X	X	X	X	X	X
Generator Circuit Breaker	X	X	X	X	X	X
Over-voltage Protection	X	X	X	X	X	X
Under-voltage Protection	-	-	X	X	X	X
Under/Over-frequency Protection	X	X	X	X	X	X
Ground Fault Protection	-	-	X	X	X	X
Over-current Relay w/Voltage Restraint	-	-	-	-	X	X
Synchronizing[3]	Manual	Manual	Manual	Manual	Manual	Automatic
Power Factor or Voltage Regulation			X	X	X	X

c. DISCONNECT DEVICE: The Producer shall provide, install, own and maintain the interconnection disconnect device required by Section B.3.b at a location readily accessible to the Utility. Such device shall normally be located near the Utility's meter or meters for sole operation by the Utility. The interconnection disconnect device and its precise location shall be specified by the Utility. At the Producer's option and request, the Utility will provide, install, own and maintain the disconnect device on the Utility's system as special facilities in accordance with Section F.

[1] Detailed requirements are specified in the Utility's current operating, metering and equipment protection publications, as revised from time to time by the Utility and available to the Producer upon request. For a particular generator application, the Utility will furnish its specific control, protective and safety requirements to the Producer after the exact location of the generator has been agreed upon and the interconnection voltage level has been established.

[2] This is a transformer interconnected with no other Producers and serving no other Utility customers. Although the dedicated transformer is not a requirement for generators rated 10 kw or less, its installation is recommended by the Utility.

[3] This is a requirement for synchronous and other types of generators with stand-alone capability. For all such generators, the Utility will also require the installation of "reclose blocking" features on its system to block certain operations of the Utility's automatic line restoration equipment.

(Continued)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

B. INTERCONNECTION FACILITIES (continued)

4. UTILITY SYSTEM ADDITIONS AND REINFORCEMENTS

a. Except as provided for in Section B.5, all additions to and reinforcements of the Utility's system necessary to interconnect with and receive power deliveries from the Producer's generation will be provided, installed, owned and maintained by the Utility as special facilities in accordance with Section F. Such additions and reinforcements may include the installation of a Utility distribution or transmission line extension or the increase of capacity in the Utility's existing distribution or transmission lines. The Utility shall determine whether any such additions or reinforcements shall include an increment of additional capacity for the Utility's use in furnishing service to its customers. If so, then the costs of providing, installing, owning and maintaining such additional capacity shall be borne by the Utility and/or its customers in accordance with the Utility's applicable tariffs on file with and authorized by the California Public Utilities Commission (Commission).

b. The Producer shall advance to the Utility its estimated costs of performing a preliminary or detailed engineering study as may be reasonably required to identify any Producer related Utility system additions and reinforcements. Where such preliminary or detailed engineering study involves analysis of the Utility's transmission lines (60 kv and higher), the Utility shall complete its study within twelve calendar months of receiving all necessary plans and specifications from the Producer.

5. PRODUCER-INSTALLED UTILITY-OWNED LINE EXTENSIONS: The Producer may at its option provide and install an extension of the Utility's distribution or transmission lines where required to complete the Producer's interconnection with the Utility. Such extension shall be installed by contractors approved by the Utility and in accordance with its design and specifications. The Producer shall pay the Utility its estimated costs of design, administration and inspection as may be reasonably required to assure such extension is installed in compliance with the Utility's requirements. Upon final inspection and acceptance by the Utility, the Producer shall transfer ownership of the line extension to the Utility where thereafter it shall be owned and maintained as special facilities in accordance with Section F. This provision does not preclude the Producer from installing, owning and maintaining a distribution or transmission line extension as part of its other Producer-owned interconnection facilities.

6. COSTS OF FUTURE UTILITY SYSTEM ALTERATIONS: The Producer shall be responsible for the costs of only those future Utility system alterations which are directly related to the Producer's presence or necessary to maintain the Producer's interconnection in accordance with the Utility's applicable operating, metering and equipment publication in effect when the Producer and the Utility entered into a written form of power purchase agreement. Alterations made at the Producer's expense shall specifically exclude increases of existing line capacity necessary to accommodate the other Producers or Utility customers. Such alterations may, however, include relocation or undergrounding of the Utility's distribution or transmission lines as may be ordered by a governmental authority having jurisdiction.

7. ALLOCATION OF THE UTILITY'S EXISTING LINE CAPACITY: For two or more Producers seeking to use an existing line, a first come, first served approach shall be used. The first Producer to request an interconnection shall have the right to use the existing line and shall incur no obligation for costs associated with future line upgrades needed to accommodate other Producers or customers. The Utility's power purchase agreement shall specify the date by which the Producer must begin construction. If that date passes and construction has not commenced, the Producer shall be given 30 days to correct the deficiency after receiving a reminder from the Utility that the construction start-up date has passed. If construction has not commenced after the 30-day corrective period, the Utility shall have the right to withdraw its commitment to the first Producer and offer the right to interconnect on the existing line to the next Producer in order. If two Producers establish the right of first-in-time simultaneously, the two Producers shall share the costs of any additional line upgrade necessary to facilitate their cumulative capacity requirements. Costs shall be shared based on the relative proportion of capacity each Producer will add to the line.

(Continued)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

C. ELECTRIC SERVICE FROM THE UTILITY: If the Producer requires regular, supplemental, interruptible or standby service from the Utility, the Producer shall enter into separate contractual arrangements with the Utility in accordance with the Utility's applicable electric tariffs on file with and authorized by the Commission.

D. OPERATION

1. PREPARALLEL INSPECTION: In accordance with Section A.7, the Utility will inspect the Producer's interconnection facilities prior to providing it with written authorization to commence parallel operation. Such inspection shall determine whether or not the Producer has installed certain control, protective and safety equipment to the Utility's specifications. Where the Producer's generation has a rated output in excess of 100 kw, the Producer shall pay the Utility its estimated costs of performing the inspection.

2. JURISDICTION OF THE UTILITY'S SYSTEM DISPATCHER: The Producer's generation while operating in parallel with the Utility's system is at all times under the jurisdiction of the Utility's system dispatcher. The system dispatcher shall normally delegate such control to the Utility's designated switching center.

3. COMMUNICATIONS: The Producer shall maintain telephone service from the local telephone company to the location of the Producer's generation. In the event such location is remote or unattended, telephone service shall be provided to the nearest building normally occupied by the Producer's generator operator. The Utility and the Producer shall maintain operating communications through the Utility's designated switching center.

4. GENERATOR LOG: The Producer shall at all times keep and maintain a detailed generator operations log. Such log shall include, but not be limited to, information on unit availability, maintenance outages, circuit breaker trip operations requiring manual reset and unusual events. The Utility shall have the right to review the Producer's log.

5. REPORTING ABNORMAL CONDITIONS: The Utility shall advise the Producer of abnormal conditions which the Utility has reason to believe could affect the Utility's operating conditions or procedures. The Producer shall keep the Utility similarly informed.

6. POWER FACTOR: The Producer shall furnish reactive power as may be reasonably required by the Utility.

   a. The Utility reserves the right to specify that generators with power factor control capability, including synchronous generators, be capable of operating continuously at any power factor between 95 percent leading (absorbing vars) and 90 percent lagging (producing vars) at any voltage level within ± 5.0 percent of rated voltage. For other types of generators with no inherent power factor control capability, the Utility reserves the right to specify the installation of capacitors by the Producer to correct generator output to near 95 percent leading power factor. The Utility may also require the installation of switched capacitors on its system to produce reactive support equivalent to that provided by operating a synchronous generator of the same size between 95 percent leading and 90 percent lagging power factor.
   b. Where either the Producer or the Utility determines that it is not practical for the Producer to furnish the Utility's required level of reactive power or when the Utility specifies switched capacitors in its system pursuant to Section D.6.a, the Utility will provide, install, own and maintain the necessary devices on its system in accordance with Section F.

E. INTERFERENCE WITH SERVICE AND COMMUNICATION FACILITIES

1. GENERAL: The Utility reserves the right to refuse to connect to any new equipment or to remain connected to any existing equipment of a size or character that may be detrimental to the Utility's operations or service to its customers.

(Continued)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

E. INTERFERENCE WITH SERVICE AND COMMUNICATION FACILITIES (continued)

2. The Producer shall not operate equipment that superimposes upon the Utility's system a voltage or current which causes interference with the Utility's operations, service to the Utility's customers or interference to communication facilities. If the Producer causes service interference to others, the Producer must diligently pursue and take corrective action at the Producer's expense after being given notice and reasonable time to do so by the Utility. If the Producer does not take timely corrective action, or continues to operate the equipment causing the interference without restriction or limit, the Utility may, without liability, disconnect the Producer's equipment from the Utility's system until a suitable permanent solution provided by the Producer is operational at the Producer's expense.

F. SPECIAL FACILITIES

1. Where the Producer requests the Utility to furnish interconnection facilities or where it is necessary to make additions to or reinforcements of the Utility's system and the Utility agrees to do so, such facilities shall be deemed to be special facilities and the costs thereof shall be borne by the Producer, including such continuing ownership costs as may be applicable.

2. Special facilities are (a) those facilities installed at the Producer's request which the Utility does not normally furnish under its tariff schedules, or (b) a prorata portion of existing facilities requested by the Producer, allocated for the sole use of such Producer, which would not normally be allocated for such sole use. Unless otherwise provided by the Utility's filed tariff schedules, special facilities will be installed, owned and maintained or allocated by the Utility as an accommodation to the Producer only if acceptable for operation by the Utility and the reliability of service to the Utility's customers is not impaired.

3. Special Facilities will be furnished under the terms and conditions of the Utility's "Agreement for Installation or Allocation of Special Facilities for Parallel Operation of Nonutility-owned Generation and/or Electrical Standby Service" (Form 79-280, effective June 1984) and its Appendix A, "Detail of Special Facilities Charges" (Form 79-702, effective June 1984). Prior to the Producer signing such an agreement, the Utility shall provide the Producer with a breakdown of special facilities costs in a form having detail sufficient for the information to be reasonably understood by the Producer. The special facilities agreement will include, but is not limited to, a binding quotation of charges to the Producer and the following general terms and conditions:

   a. Where facilities are installed by the Utility for the Producer's use as special facilities, the Producer shall advance to the Utility its estimated installed cost of the special facilities. The amount advanced is subject to the monthly ownership charge applicable to customer-financed special facilities as set forth in Section I of the Utility's Rule No. 2.

   b. At the Producer's option, and where such Producer's generation is a qualifying facility[4] and the Producer has established credit worthiness to the Utility's satisfaction, the Utility shall finance those special facilities it deems to be removable and reusable equipment. Such equipment shall include, but not be limited to, transformation, disconnection and metering equipment.

   c. Existing facilities allocated for the Producer's use as special facilities and removable and reusable equipment financed by the Utility in accordance with Section F.3.b are subject to the monthly ownership charge applicable to Utility-financed special facilities as set forth in Section I of Rule 2.

[4]A qualifying facility is one which meets the requirements established by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

(Continued)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

F. SPECIAL FACILITIES (continued)

d. Where the Producer elects to install and deed to the Utility an extension of the Utility's distribution or transmission lines for use as special facilities in accordance with Section B.5, the Utility's estimate of the installed cost of such extension shall be subject to the monthly ownership charge applicable to customer-financed special facilities as set forth in Section I of the Rule No. 2.

4. Where payment or collection of continuing monthly ownership charges is not practicable, the Producer shall be required to make an equivalent one-time payment in lieu of such monthly charges.

5. Costs of special facilities borne by the Producer may be subject to downward adjustment when such special facilities are used to furnish permanent service to a customer of the Utility. This adjustment will be based upon the extension allowance or other such customer allowance which the Utility would have utilized under its then applicable tariffs if the special facilities did not otherwise exist. In no event shall such adjustment exceed the original installed cost of that portion of the special facilities used to serve a new customer. An adjustment, where applicable, will consist of a refund applied to the Producer's initial payment for special facilities and/or a corresponding reduction of the ownership charge.

G. EXCEPTIONAL CASES: Where the application of this rule appears impractical or unjust, the Producer may refer the matter to the Commission for special ruling or for the approval of special conditions.

H. INCORPORATION INTO POWER PURCHASE AGREEMENTS: Pursuant to Decision No. 83-10-093, if in accordance with Section A.4 the Producer enters into a written form of power purchase agreement with Utility, a copy of the Rule No. 21 in effect on the date of execution will be appended to, and incorporated by reference into, such power purchase agreement. The Rule appended to such power purchase agreement shall then be applicable for the term of the Producer's power purchase agreement with the Utility. Subsequent revisions to this rule shall not be incorporated into the rule appended to such power purchase agreement.