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October 30, 1990

HAND DELIVERED

Mr. Steve C. Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399-0850

Re: Planning Hearings on Load Forecasts, Generation Expansion Plans, and Cogeneration Prices for Peninsular Florida's Electric Utilities; FPSC Docket No. 900004-EU

Dear Mr. Tribble:

Pursuant to Order No. 23625 issued in Docket No. 891049-EU on October 16, 1990, we submit herewith for filing Tampa Electric's Ten Year Power Resource Plan along with the following Tampa Electric tariff sheets:

Third Revised Sheet No. 8.010
Second Revised Sheet No. 8.020
Fourteenth Revised Sheet No. 8.030
Third Revised Sheet No. 8.050
First Revised Sheet No. 8.060
Original Sheet No. 8.061
Second Revised Sheet No. 8.070
Second Revised Sheet No. 8.080
Third Revised Sheet No. 8.090
Fourth Revised Sheet No. 8.100
Second Revised Sheet No. 8.101
Original Sheet No. 8.102
Original Sheet No. 8.103
Original Sheet No. 8.104
Original Sheet No. 8.105
Original Sheet No. 8.106
Original Sheet No. 8.107
Original Sheet No. 8.108
Original Sheet No. 8.109
Fourth Revised Sheet No. 8.110
Original Sheet No. 8.111
Original Sheet No. 8.112
Original Sheet No. 8.113
Original Sheet No. 8.114
Original Sheet No. 8.117
Fourth Revised Sheet No. 8.120
Fifth Revised Sheet No. 8.130

Original Sheet No. 8.131
Fifth Revised Sheet No. 8.140
Fifth Revised Sheet No. 8.150
Thirteenth Revised Sheet No. 8.160
Fourth Revised Sheet No. 8.170
Sixteenth Revised Sheet No. 8.180
Tenth Revised Sheet No. 8.190
Fourth Revised Sheet No. 8.200
Original Sheet No. 8.201
Fourth Revised Sheet No. 8.210
Second Revised Sheet No. 8.220
Original Sheet No. 8.221
Third Revised Sheet No. 8.230
Third Revised Sheet No. 8.240
Second Revised Sheet No. 8.250
Fourth Revised Sheet No. 8.260
Fifth Revised Sheet No. 8.270
Original Sheet No. 8.279
Third Revised Sheet No. 8.280
Second Revised Sheet No. 8.290
Second Revised Sheet No. 8.300
Third Revised Sheet No. 8.310
Original Sheet No. 8.311
Third Revised Sheet No. 8.320
Third Revised Sheet No. 8.330
Fourth Revised Sheet No. 8.340
Original Sheet No. 8.342

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FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
09754 OCT 30 1990
FPSC-RECORDS/REPORTING

Original Sheet No. 8.345
Original Sheet No. 8.346
Original Sheet No. 8.347
Original Sheet No. 8.348
Original Sheet No. 8.349
Fourth Revised Sheet No. 8.350
Original Sheet No. 8.351
Original Sheet No. 8.352
Second Revised Sheet No. 8.353
Second Revised Sheet No. 8.354
Second Revised Sheet No. 8.355
Original Sheet No. 8.356
Original Sheet No. 8.357
Third Revised Sheet No. 8.358
Third Revised Sheet No. 8.360
Original Sheet No. 8.361
Original Sheet No. 8.362
Original Sheet No. 8.363
Original Sheet No. 8.364
Original Sheet No. 8.365
Original Sheet No. 8.366
Original Sheet No. 8.367
Original Sheet No. 8.368
Original Sheet No. 8.369
Fourth Revised Sheet No. 8.370
Original Sheet No. 8.371
Original Sheet No. 8.372
Original Sheet No, 8.373
Original Sheet No. 8.374
Original Sheet No. 8.375
Second Revised Sheet No. 8.380
Original Sheet No. 8.384
Original Sheet No. 8.386
Original Sheet No. 8.388
Fourth Revised Sheet No. 8.390
Fourth Revised Sheet No. 8.400
Fourth Revised Sheet No. 8.410
Fourth Revised Sheet No. 8.420
Fourth Revised Sheet No. 8.430
Original Sheet No. 8.431
Original Sheet No. 8.432
Second Revised Sheet No. 8.440
Original Sheet No. 8.441
Second Revised Sheet No. 8.450
Second Revised Sheet No. 8.460
Second Revised Sheet No. 8.470
First Revised Sheet No. 8.500
First Revised Sheet No. 8.530
First Revised Sheet No. 8.540
First Revised Sheet No. 8.550
First Revised Sheet No. 8.560
First Revised Sheet No. 8.570
First Revised Sheet No. 8.580
First Revised Sheet No. 8.590
Original Sheet No. 8.591
First Revised Sheet No. 8.600
First Revised Sheet No. 8.610
First Revised Sheet No. 8.660
Original Sheet No. 8.661

Also enclosed is a copy of the above tariff sheets marked in legislative format to identify the changes which have been made.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

TO: EAG/ DEAN

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
encls.

TAMPA ELECTRIC COMPANY

Ten Year Power Resource Plan
(1991-2000)

Overview

Tampa Electric's objective with the proposed Generation Expansion Plan is to continue to provide economical and reliable service to Tampa Electric Company Customers. The ten year power resource plan for Tampa Electric is based on a detailed system reliability analysis, economic evaluation of both demand and supply side alternatives and consideration of any strategic concerns in maintaining this objective.

The current power resource plan as shown in Table 1 reflects the need for additional peaking and combined cycle generating capacity during the next ten-year period. Based on an analysis of system reliability, additional generating capacity is first needed on the system in 1995. A combustion turbine (CT) will be constructed in 1995 and will be followed by a second CT addition in 1996. Both CT's will be modular components of a combined cycle (CC) unit with the addition of a heat recovery steam generator (HRSG) in 1997.

A second phased combined cycle addition is needed by the year 2000 with the addition of a combustion turbine in 1998 and 1999 and an HRSG in the year 2000. Hookers Point Units 1-5 will be returned to full service from standby status by January 1, 1991.

Reliability Analysis

A system reliability analysis determines the adequacy of the existing and future generating resources required to reliably satisfy the current and projected demand and energy requirements of our system.

The primary measure of generating system reliability is the assisted loss of load probability (LOLP) which incorporates both the isolated system reliability and the availability of other resources via interconnections with other generating systems. A specific LOLP criteria is established from an analysis of historical system performance data, a review of acceptable

TABLE 1

BASE CASE EXPANSION PLAN

YEAR	10-YR. EXPANSION PLAN	ISOLATED LOLP (D/Y)	NET ASSISTED LOLP (D/Y)	FIRM WINTER RESERVE(%)
1993	TPS	22.27	0.04	32.3
1994	-	26.47	0.07	28.4
1995	CT	27.00	0.10	27.8
1996	CT	27.45	0.10	27.1
1997	HRSG	29.25	0.10	26.0
1998	CT	29.59	0.09	25.6
1999	CT	29.79	0.09	25.1
2000	HRSG	31.21	0.10	24.2

TPS - 295 MW PURCHASE AGREEMENT WITH TECO POWER SERVICES
CT - COMBUSTION TURBINE (83.5 MW WINTER/65.1 MW SUMMER)
HRSG - HEAT RECOVERY STEAM GENERATOR (66.0 MW WINTER/61.8 MW SUMMER). COMBINES WITH TWO CTs TO FORM COMBINED CYCLE UNIT.

utility industry standards for comparable regions and applying judgement regarding operating conditions specific to the Tampa Electric system. The current reliability criteria for our system is an assisted LOLP of 0.1 loss-of-load days per year.

There are primary and secondary factors that determine the reliability of our electrical system. Primary factors are the expected firm demand (MW) and energy (GWH) requirements as shown in Appendix A and the expected generating capability which combines capacity and availability. Secondary factors are modifications or additions to the primary factors such as conservation and load management programs, firm interchange and non-firm interchange. Since the secondary factors are developed from the primary factors, a short discussion of secondary factors is appropriate.

<u>Conservation and Load Management</u>. Tampa Electric Company currently has a number of demand side management programs in effect. These programs will be modified annually to meet our Customer's needs in the most economic manner. The impact of these programs is included in Tampa Electric system reserve without compromising firm load system reliability.

<u>Non-firm Interchange.</u> Non-firm interchange reflects the ability of external generating resource to supply energy on an emergency basis via the interconnections with other utilities. The capability of the external generating resources to supply power is a function of the individual coincident system demand and energy requirements, availability of generating capacities and the coincident capability of the transmission system required to deliver the power. The LOLP criteria of 0.1 day per year reflects the probabilistic amount of time that both the isolated and assistance areas would not be able to meet 100% of the firm demand and energy requirements for our system.

<u>Firm Interchange.</u> The only firm power sale under contract for the years 1991-2000 is a 26 MW sale in the year 1992. All other proposed power sales are on an as-available basis and do not affect

system reliability or new generating capacity requirements.

Tampa Electric Company has a firm purchase power agreement beginning in 1993. The power agreement will provide capacity and energy from the co-utilization of generating resources with Seminole Electric Cooperative, Inc. and TECO Power Services. The agreement is based on restricted use of a 145 MW block of Big Bend unit 4 coal capacity, 220 MW of combined cycle capacity and 75 MW of combustion turbine capacity will be sold to Seminole Electric Cooperative for use from 1993-2003. This capacity is available for utilization by Tampa Electric if both Seminole Units 1 and 2 are available. The net availability of the combined resources (440 MW) to Tampa Electric is expected to be comparable with existing generating unit availabilities on our system.

Tampa Electric Company will have 313 MW of net cogeneration on our system in 1991. This amount is expected to increase to a total of 400 MW by the year 2000 of which 308 MW is projected to be used by the cogenerators to serve internal load requirements. Of the remaining 92 MW, 67.5 MW, are planned to be purchased by Tampa Electric Company from the cogenerators on a firm basis. The cogeneration purchased on a firm basis will be provided by resource recovery and phosphate facilities. There are 20 MW of purchased cogeneration available on a non-firm basis by the year 1991. This is projected to increase to 21.5 MW by the year 2000.

Economic Evaluation

Various power resource scenarios, comprised of a mixture of generating technologies, joint participation and purchased power generation, and demand side programs are developed. These alternatives are analyzed, along with future system demand and energy requirements and existing generating capabilities, to arrive at a number of generation expansion alternatives. Each alternative satisfies the established reliability criteria.

The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, in-service year, etc. The fixed charges resulting from the capital expenditures are expressed in "present worth" dollars for comparison.

The fuel, and the operating and maintenance costs associated with each scenario are projected. These projections, which are also expressed in "present worth" dollars, are combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative power resource plan. Two primary considerations in this evaluation are the selected alternative generation technologies and the associated fuel requirements.

Alternative Technologies. A feasibility study is performed to assess a wide range of generating technologies that are economically viable for the Tampa Electric Company service area. Normally, regional geography and weather conditions screen out most hydro, tidal, geothermal, and wind-type technologies. Additional screening may also eliminate certain technologies from a certain study period because of lead-time, public acceptance, safety and proven demonstration and commercialization.

Fuel Requirements. A forecast of energy sources and fuel requirements is shown in Appendix A . As shown in this table, Tampa Electric Company primarily will rely on coal fuel generation to meet existing and future demand and energy requirements. While the company will add oil and natural gas capacity in the next decade, that capacity will operate at a low percentage of the time to help serve system peaks. Coal will continue to provide 96% - 99% of the total system fuel requirements for Tampa Electric. This strategy of utilizing coal, our nation's most abundant domestic fuel, is both practical and cost-effective and minimizes exposure to disruption in fuel supply or market price uncertainties.

Following this evaluation, the most economical alternatives are subjected to a detailed strategic concerns analysis.

Strategic Concerns

Strategic issues which affect the type, capacity and/or timing of Tampa Electric's future generation resource requirements are analyzed in the annual Power Resource Study. These issues such as high and low fuel price, natural gas availability, environmental legislation and potential joint ownership projects, are evaluated in the process of determining the optimal expansion plan. In this way, an economically sound expansion plan is selected which has the flexibility to respond to future technological and economical changes.

APPENDIX A

ALTERNATIVE TECHNOLOGY ASSUMPTIONS
(MID YEAR 1991 $)

	FUEL TYPE	LEAD TIME (YEARS)	INSTALLED * COST W/O AFUDC ($/KW)	O & M COSTS FIXED ($/KW)	O & M COSTS VARIABLE ($/MWH)	EQUIVALENT AVAILABILITY (%) (INCLUDING PLANNED MAINTENANCE)	AVERAGE ANNUAL HEAT RATE (BTU/KWH)
1. BASE LOAD CAPACITY							
500 MW COAL W FGD	HSC	7	1274	23.50	5.71	80.6	9829
400 MW IGCC	CG	6	1597	41.83	2.8	85.7	9220
2. INTERMEDIATE CAPACITY							
220 MW COMBINED CYCLE (233 MW – WINTER, 196 MW – SUMMER)	NG	4	595	4.20	4.2	90.5	8055
100 MW FUEL CELL	NG	4	1172	8.73	5.39	91.6	8549
99 MW PHOTOVOLATIC SOLAR CELL	SL	2	2630	6.90	3.34	93.3	22765
80 MW SOLAR THERMAL UNIT	SL	2	3016	47.87	0.86	92.4	24391
3. PEAKING CAPACITY							
75 MW COMBUSTION TURBINE (83.5 MW – WINTER, 67.1 MW – SUMMER)	LS#2	2	433	0.86	8.41	92.4	14020

NOTE: IGCC – INTEGRATED GASIFICATION COMBINED CYCLE
HSC – HIGH SULFUR COAL
CG – COAL GAS
NG – NATURAL GAS
LS#2 – #2 OIL
SL – SUNLIGHT

* ASSUMES OVERNIGHT CONSTRUCTION

UTILITY: TAMPA ELECTRIC COMPANY

HISTORY AND FORECAST
AS OF JANUARY 1, 1990
BASE (MOST PROBABLE) LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SUMMER PEAK DEMAND						WINTER PEAK DEMAND						ENERGY	
YEAR	TOTAL (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGEMENT (MW)	QF LOAD (MW)	NET DEMAND (MW)	YEAR	TOTAL (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGEMENT (MW)	QF LOAD (MW)	NET DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR %
1981	2089	221	0	0	1868	1980/81	2373	198	0	0	2175	1981	11388	59.8
1982	1918	146	0	14	1758	1981/82	2272	128	0	14	2130	1982	10588	56.7
1983	2095	215	3	24	1853	1982/83	2106	192	5	22	1887	1983	11146	67.4
1984	2144	253	12	25	1854	1983/84	2197	175	13	24	1985	1984	11868	68.3
1985	2436	273	26	48	2089	1984/85	2814	204	33	49	2528	1985	12497	56.4
1986	2263	151	37	63	2012	1985/86	2666	170	70	68	2358	1986	11916	57.7
1987	2544	244	54	92	2154	1986/87	2373	152	80	105	2036	1987	12348	69.2
1988	2585	221	76	109	2179	1987/88	2728	205	114	108	2301	1988	13151	65.2
1989	2812	315	73	191	2233	1988/89	2774	242	128	190	2214	1989	13705	70.7
1990	2797	279	76	191	2251	1989/90	2959	244	107	157	2451	1990	14198	66.1
(1981-90) % AAGR	3.3						2.5				1.3		2.5	
1991	2925	258	80	248	2339	1990/91	3220	237	174	248	2561	1991	14360	64.0
1992	3007	245	83	271	2408	1991/92	3311	226	180	271	2634	1992	14632	63.4
1993	3090	248	87	285	2470	1992/93	3400	229	186	285	2700	1993	14993	63.4
1994	3170	251	91	290	2538	1993/94	3488	232	193	290	2773	1994	15430	63.5
1995	3243	245	94	293	2611	1994/95	3569	227	199	293	2850	1995	15834	63.4
1996	3316	241	98	296	2681	1995/96	3648	222	205	296	2925	1996	16236	63.4
1997	3390	237	101	299	2753	1996/97	3730	219	212	299	3000	1997	16657	63.4
1998	3463	232	105	302	2824	1997/98	3810	214	218	302	3076	1998	17077	63.4
1999	3538	227	109	305	2897	1998/99	3891	210	224	305	3152	1999	17506	63.4
2000	3610	222	112	308	2968	1999/00	3971	204	230	308	3229	2000	17934	63.4
(1991-00) % AAGR	2.4						2.4				2.6		2.5	

NOTE: COLUMN (2) = SUM (3) THROUGH (6). COLUMN (8) = SUM (9) THROUGH (12).
COLUMN (5) & (11), SELF-SERVICE GENERATION, ARE QF LOAD SERVED BY QF GENERATION.

UTILITY: TAMPA ELECTRIC COMPANY

FUEL PRICE FORECAST (1991–2000)
BASE CASE OIL AND GAS PRICES

	RESIDUAL OIL (BY SULFUR CONTENT) 0.7 – 2.0% (1)			DISTILLATE			NATURAL GAS	
YEAR	$/BBL	$/MBTU	ESC (%)	$/BBL	$/MBTU	ESC (%)	$/MBTU	ESC (%)
1991	20.14	3.19	----	29.21	5.04	----	3.52	----
1992	31.93	5.05	58.31	42.08	7.26	44.05	5.24	48.86
1993	34.07	5.39	6.73	42.11	7.27	0.14	5.70	8.78
1994	37.14	5.88	9.09	46.11	7.95	9.35	6.18	8.42
1995	41.08	6.50	10.54	51.28	8.84	11.19	6.80	10.03
1996	44.76	7.08	8.92	56.61	9.76	10.41	7.39	8.68
1997	48.28	7.64	7.91	61.71	10.64	9.02	7.95	7.58
1998	52.44	8.30	8.64	67.10	11.57	8.74	8.62	8.43
1999	56.43	8.93	7.59	72.28	12.46	7.69	9.26	7.42
2000	62.36	9.87	10.53	78.47	13.53	8.59	11.22	21.17

NOTES:
1. ALWAYS LESS THAN 1%
2. HEAT CONTENT OF RESIDUAL OIL: 6.321 MBTU/BBL
3. HEAT CONTENT OF DISTILLATE: 5.796 MBTU/BBL

UTILITY: TAMPA ELECTRIC CO.

FUEL PRICE FORECAST (1991-2000)
HIGH AND MEDIUM SULFUR COAL PRICES

	MEDIUM SULFUR COAL			HIGH SULFUR COAL		
	1.0% - 2.0%		ESC.	MORE THAN 2.0%		ESC.
YEAR	$/TON	$/MBTU	%	$/TON	$/MBTU	%
1991	49.45	1.99	----	22.22	1.01	----
1992	51.69	2.08	4.52	22.88	1.04	2.97
1993	54.92	2.21	6.25	23.54	1.07	2.88
1994	58.15	2.34	5.88	24.64	1.12	4.67
1995	61.38	2.47	5.56	25.96	1.18	5.36
1996	64.86	2.61	5.67	27.50	1.25	5.93
1997	68.83	2.77	6.13	28.82	1.31	4.80
1998	72.56	2.92	5.42	30.36	1.38	5.34
1999	76.79	3.09	5.82	31.90	1.45	5.07
2000	81.51	3.28	6.15	33.66	1.53	5.52

NOTES: 1. HEAT CONTENT OF MEDIUM SULFUR COAL: 24.85 MBTU/TON
2. HEAT CONTENT OF HIGH SULFUR COAL: 22.0 MBTU/TON

UTILITY: TAMPA ELECTRIC COMPANY

FUELS FORECAST (1990 – 2000)
AS OF JANUARY 1, 1990

YEAR	FIRM PURCHASES * $/MWH	ESCALATION %
1991		
1992		
1993	59.18	
1994	63.63	7.52
1995	70.42	10.67
1996	75.86	7.73
1997	84.66	11.60
1998	90.15	6.48
1999	95.47	5.90
2000	113.83	19.23

* TPS PURCHASE AGREEMENT FOR 295 MW's FROM THE HARDEE POWER STATION.

UTILITY: TAMPA ELECTRIC COMPANY

BASE CASE

ECONOMIC ASSUMPTIONS

AFUDC RATE

8.53 %

CAPITALIZATION RATIOS

DEBT	45 %
PREFERRED	7 %
EQUITY	48 %

RATE OF RETURN

DEBT	10.10 %
PREFERRED	9.1 %
EQUITY	13.5 %

INCOME TAX RATE

FEDERAL	34.0 %
STATE	5.5 %
EFFECTIVE	37.63 %

OTHER TAX RATE

2.5 %

DISCOUNT RATE

9.95 %

TAX DEPRECIATION LIFE

20 YEARS

UTILITY: TAMPA ELECTRIC COMPANY

BASE CASE

ECONOMIC ESCALATION ASSUMPTIONS

YEAR	GENERAL INFLATION %	PLANT CONSTRUCTION COST %	FIXED O & M COST %	VARIABLE O & M COST %
1990	N/A	5.5	5.3	5.3
1991		5.5	5.2	5.2
1992		5.1	4.8	4.8
1993	SEE	5.1	4.8	4.8
1994	NOTE	5.1	4.8	4.8
1995		5.1	4.8	4.8
1996		5.1	4.8	4.8
1997		5.1	4.8	4.8
1998		5.1	4.8	4.8
1999		5.1	4.8	4.8
2000 & BEYOND		5.1	4.8	4.8

SOURCE: ECONOMIC & LOAD FORECASTING SECTION OF POWER RESOURCE PLANNING DEPARTMENT.

NOTE: PLANT AND O & M RATES INCLUDE INFLATION AND ESCALATION COMPONENTS.

UTILITY: TAMPA ELECTRIC COMPANY

SUMMARY OF NEW UNIT ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)
				NET CAPABILITY	
YEAR	UNIT TYPE	FUEL	CONSTRUCTION START MO/YR	SUMMER (MW)	WINTER (MW)
1/1995	CT	LO	1/1991	67.1	83.5
1/1996	CT	LO	1/1994	67.1	83.5
1/1997	HRSG	N/A *	1/1993	61.8	66.0
1/1998	CT	LO	1/1996	67.1	83.5
1/1999	CT	LO	1/1997	67.1	83.5
1/2000	HRSG	N/A *	1/1996	61.8	66.0

* WASTE HEAT FROM COMBUSTION TURBINE UNITS CT 1 – 4 ADDED IN 1995, 1996, 1998 AND 1999.

NOTE: WHEN THE HRSG'S ARE ADDED TO THE CT'S THE UNITS ARE SWITCHED FROM BURNING LIGHT OIL (LO) TO NATURAL GAS.

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF WINTER PEAK
CASE: <u>BASE CASE</u>

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INSTALLED CAPACITY						RESERVE MARGIN	
YEAR	EXISTING & CERTIFIED	GENERIC ADDITIONS	CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM QF (MW)	TOTAL AVAILABLE CAPACITY (MW)	COINCIDENT FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1990 /91	3191		0	41	3232	2561	671	26
1991 /92	3226		0	58	3284	2634	650	25
1992 /93	3226		295	64	3585	2700	885	33
1993 /94	3226		295	68	3589	2773	816	29
1994 /95	3226	83.5	295	68	3672	2850	822	29
1995 /96	3226	83.5	295	68	3756	2925	831	28
1996 /97	3226	66.0	295	68	3822	3000	822	27
1997 /98	3226	83.5	295	68	3905	3076	829	27
1998 /99	3226	83.5	295	68	3989	3152	837	27
1999 /00	3226	66.0	295	68	4055	3229	826	26

NOTE: COLUMN (5) IS THE SUM OF COLUMNS (3) OF PAGES A17 & A19, BY YEAR.

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF SUMMER PEAK
CASE: BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INSTALLED CAPACITY						RESERVE MARGIN	
YEAR	EXISTING & CERTIFIED	GENERIC ADDITIONS	CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM QF (MW)	TOTAL AVAILABLE CAPACITY (MW)	COINCIDENT FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1991	3196		0	41	3237	2339	898	38
1992	3196		0	58	3254	2408	846	35
1993	3196		295	64	3555	2470	1085	44
1994	3196		295	68	3559	2538	1021	40
1995	3196	67.1	295	68	3626	2611	1015	39
1996	3196	67.1	295	68	3693	2681	1012	38
1997	3196	61.8	295	68	3755	2753	1002	36
1998	3196	67.1	295	68	3822	2824	998	35
1999	3196	67.1	295	68	3889	2897	992	34
2000	3196	61.8	295	68	3951	2968	983	33

NOTE: COLUMN (5) IS THE SUM OF COLUMNS (3) OF PAGES A17 & A19, BY YEAR.

UTILITY: TAMPA ELECTRIC COMPANY

DESIGNATED AVOIDED UNIT

PLANT NAME (TYPE):	COMBUSTION TURBINE
NET CAPACITY (MW):	* 75
BOOK LIFE (YRS):	30

INSTALLED COST (IN-SERVICE YEAR 1996)

TOTAL INSTALLED COST ** ($/KW):	592.4
DIRECT CONSTRUCTION COST ($/KW-91):	461.9
AFUDC AMOUNT ($/KW):	35.7
ESCALATION ($/KW):	94.8
FIXED O & M ($/KW-YR): (1996)	1.16
VARIABLE O & M ($/MWH): (1996)	10.63
ASSUMED CAPACITY FACTOR:	10.0%
K FACTOR ***	1.6446

* THIS IS THE NET CONTINOUS UNIT RATING . THE WINTER/SUMMER UNIT RATINGS ARE 83.5MW AND 67.1MW RESPECTIVELY .

** TOTAL INSTALLED COST = DIRECT CONSTRUCTION COST + AFUDC + ESCALATION

*** K FACTOR DEVELOPED ON FOLLOWING PAGE

UTILITY: TAMPA ELECTRIC CC MPANY

FINANCIAL ASSUMPTIONS
FOR THE DEVELOPMENT OF K FACTOR

UNIT: COMBUSTION TURBINE

CAPITALIZATION RATIOS:

DEBT:	45	%
PREFERRED:	7	%
EQUITY:	48	%

RATE OF RETURN:

DEBT:	10.1	%
PREFERRED:	9.1	%
EQUITY:	13.5	%
TAX RATE:	37.63	%
AFUDC:	8.53	%
DISCOUNT RATE:	9.95	%
BOOK LIFE:	30	YEAR
INVESTMENT TAX CREDIT LIFE:	N/A	
START YEAR FOR CONSTRUCTION:	1994	YEAR
IN-SERVICE YEAR:	1996	YEAR

CONSTRUCTION SPENDING CURVE

YEAR	% CONSTRUCTION EXPENDITURES*	
-8	-	%
-7	-	%
-6	-	%
-5	-	%
-4	-	%
-3	-	%
-2	25	%
-1	75	%
0	0	%

* To be applied to direct construction costs.

UTILITY: TAMPA ELECTRIC COMPANY

FIXED CHARGE CALCULATION FOR DEVELOPEMENT OF K FACTOR FOR THE "AVOIDED UNIT"

UNIT: COMBUSTION TURBINE

(1) CALENDAR YEAR	(2) MID-YEAR RATE-BASE ($000)	(3) DEBT ($000)	(4) PREFERRED STOCK ($000)	(5) COMMON EQUITY ($000)	(6) INCOME TAXES ($000)	(7) OTHER TAXES & INSURANCE ($000)	(8) DEPREC. ($000)	(9) DEFERRED TAXES ($000)	(10) TOTAL FIXED CHARGES ($000)	(11) PRESENT WORTH FIXED CHARGES ($000)	(12) CUMULATIVE PW FIXED CHARGES ($000)
1996	43,550	1,979	277	2,822	1,870	1,111	1,481	279	9,541	9,541	9,541
1997	41,414	1,882	264	2,684	1,778	1,111	1,481	1,031	9,200	8,367	17,908
1998	38,982	1,772	248	2,526	1,674	1,111	1,481	872	8,812	7,289	25,196
1999	36,700	1,668	234	2,378	1,576	1,111	1,481	730	8,448	6,355	31,552
2000	34,553	1,570	220	2,239	1,484	1,111	1,481	601	8,105	5,546	37,097
2001	32,529	1,478	207	2,108	1,397	1,111	1,481	484	7,782	4,843	41,940
2002	30,591	1,390	195	1,982	1,314	1,111	1,481	429	7,473	4,229	46,169
2003	28,681	1,304	183	1,859	1,232	1,111	1,481	429	7,168	3,690	49,859
2004	26,770	1,217	171	1,735	1,150	1,111	1,481	431	6,863	3,213	53,072
2005	24,859	1,130	158	1,611	1,067	1,111	1,481	429	6,558	2,792	55,864
2006	22,948	1,043	146	1,487	985	1,111	1,481	431	6,253	2,422	58,286
2007	21,037	956	134	1,363	903	1,111	1,481	429	5,948	2,095	60,381
2008	19,127	869	122	1,239	821	1,111	1,481	431	5,644	1,808	62,189
2009	17,216	782	110	1,116	739	1,111	1,481	429	5,339	1,555	63,744
2010	15,305	696	97	992	657	1,111	1,481	431	5,034	1,334	65,078
2011	13,640	620	87	884	586	1,111	1,481	(64)	4,768	1,149	66,227
2012	12,470	567	79	808	535	1,111	1,481	(557)	4,581	1,004	67,231
2013	11,546	525	74	748	496	1,111	1,481	(557)	4,434	884	68,114
2014	10,623	483	68	688	456	1,111	1,481	(557)	4,287	777	68,892
2015	9,699	441	62	628	416	1,111	1,481	(557)	4,139	682	69,574
2016	8,775	399	56	569	377	1,111	1,481	(557)	3,992	599	70,173
2017	7,851	357	50	509	337	1,111	1,481	(557)	3,845	524	70,697
2018	6,928	315	44	449	297	1,111	1,481	(557)	3,697	459	71,156
2019	6,004	273	38	389	258	1,111	1,481	(557)	3,550	400	71,556
2020	5,080	231	32	329	218	1,111	1,481	(557)	3,402	349	71,905
2021	4,157	189	26	269	178	1,111	1,481	(557)	3,255	304	72,209
2022	3,233	147	21	209	139	1,111	1,481	(557)	3,108	264	72,473
2023	2,309	105	15	150	99	1,111	1,481	(557)	2,960	228	72,701
2024	1,386	63	9	90	59	1,111	1,481	(557)	2,813	197	72,899
2025	462	21	3	30	20	1,111	1,481	(557)	2,665	170	73,069

K-FACTOR = CPWFC / IN-SVC = 73069 / 44430 = 1.6446

IN SERVICE COST ($000)	44430
IN SERVICE YEAR	1996
BOOK LIFE (YRS)	30
EFF. TAX RATE	0.3763
DISCOUNT RATE	0.0995
OTAX & INS RATE	0.025

CAPITAL STRUCTURE

SOURCE	WEIGHT	COST
DEBT	0.45	0.101
P/S	0.07	0.091
C/S	0.48	0.135

UTILITY: TAMPA ELECTRIC COMPANY

SUMMARY OF FIRM ENERGY AND CAPACITY PAYMENTS TO SUPPLY SIDE QUALIFYING FACILITIES

UNIT TYPE: COMBUSTION TURBINE

(1) YEAR	(2) AVOIDED CAPITAL COST $/kW-MO	(3) AVOIDED* O&M COST $/kW-MO	(4) TOTAL AVOIDED CAPACITY COST $/kW-MO	(5) AVOIDED UNIT** FUEL COST CENTS/kWh
1996	4.83	0.09	4.92	147.47
1997	5.08	0.09	5.17	160.31
1998	5.33	0.10	5.43	173.88
1999	5.61	0.10	5.71	186.93
2000	5.89	0.11	6.00	202.51
2001	6.19	0.11	6.30	230.19
2002	6.51	0.12	6.63	259.57
2003	6.84	0.12	6.96	291.09
2004	7.19	0.13	7.32	325.23
2005	7.56	0.14	7.70	352.97

* THE AVOIDED O&M DOLLARS DO NOT INCLUDE A VARIABLE O&M COMPONENT .

** THE AVOIDED UNITS VARIABLE O&M COMPONENT IS INCLUDED IN IT'S FUEL COST .
THE VARIABLE O&M COSTS ARE CALCULATED ASSUMING A 10% CAPACITY FACTOR .

UTILITY: TAMPA ELECTRIC COMPANY

EXISTING GENERATING FACILITIES
AS OF OCTOBER, 1991

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				FUEL		FUEL TRANSPORTATION		COMM'L IN-SERVICE	EXPECTED RETIREMENT	GEN. MAX NAMEPLATE	NET CAPABILITY	
PLANT	UNIT NO.	LOCATION	TYPE	PRI	ALT	PRI	ALT	(MO/YR)	(MO/YR)	(kW)	SUMMER (MW)	WINTER (MW)
GANNON		HILLSBOROUGH CO. 4/30S/19E								1,288,380	1,172	1,172
	1		FS	C	NO	WA	RR	9/57	UNKNOWN	125,000	119	119
	2		FS	C	NO	WA	RR	11/58	"	125,000	118	118
	3		FS	C	NO	WA	RR	10/60	"	179,520	149	149
	4		FS	C	NO	WA	RR	11/63	"	187,500	178	178
	5		FS	C	NO	WA	RR	11/65	"	239,360	232	232
	6		FS	C	NO	WA	RR	10/67	"	414,000	362	362
	CT 1		CT	LO	NO	WA	NO	3/69	"	18,000	14	14
HOOKERS PT.*		HILLSBOROUGH CO. 4/29S/19E								232,600	206	206
	1		FS	HO	NO	WA	NO	7/48	1/2000	33,000	32	32
	2		FS	HO	NO	WA	NO	6/50	1/2000	34,500	32	32
	3		FS	HO	NO	WA	NO	8/50	1/2000	34,500	32	32
	4		FS	HO	NO	WA	NO	10/53	1/2000	49,000	42	42
	5		FS	HO	NO	WA	NO	5/55	1/2000	81,600	68	68
BIG BEND		HILLSBOROUGH CO. 4/31S/19E								1,998,000	1,818	1,848
	1		FS	C	NO	WA	NO	10/70	UNKNOWN	445,500	406	406
	2		FS	C	NO	WA	NO	4/73	"	445,500	407	407
	3		FS	C	NO	WA	NO	5/76	"	445,500	420	420
	4		FS	C	NO	WA	NO	2/85	"	486,000	441	441
	CT 1		CT	LO	NO	WA	NO	2/69	"	18,000	14	14
	CT 2		CT	LO	NO	WA	NO	11/74	"	78,750	65	80
	CT 3		CT	LO	NO	WA	NO	11/74	"	78,750	65	80
										SYSTEM TOTAL	3196	3226

* HOOKERS POINT STATION IS PRESENTLY ON LONG TERM RESERVE STANDBY (LTRS). IT IS EXPECTED TO RETURN TO SERVICE IN 1/1991.

UTILITY: TAMPA ELECTRIC COMPANY

EXISTING QUALIFYING FACILITIES
(AS OF OCTOBER 1, 1990)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				FUEL TYPE		COMMERCIAL IN-SERVICE	
FACILITY NAME	UNIT NO.	LOCATION	TYPE	PRIMARY	ALTERNATE	(MO/YR)	STATUS
IMC (1)	1	POLK	COG	WH	--	8/1981	NC
	2	"	"	"	--	12/1984	NC
CONSERV (1)	1	POLK	COG	WH	--	12/1982	C
U.S.F.	1	HILLS	COG	WH	--	5/1983	NC
	2	"		"	--	5/1987	NC
NITRAM	1	HILLS	COG	WH	--	4/1985	NC
CITY OF TAMPA REFUSE	1	HILLS	SPP	MSW	--	6/1985	C
ROYSTER (1)	1	POLK	COG	WH	--	12/1985	NC
SEMINOLE FERTILIZER	1	POLK	COG	WH	--	12/1985	NC
CITY SEWAGE (1)	1	HILLS	SPP	MG	--	11/1986	NC
	2	"	"	"	--	3/1987	NC
	3	"	"	"	--	4/1987	NC
	4	"	"	"	--	7/1989	NC
	5	"	"	"	--	7/1989	NC
HILLS. CTY REFUSE	1	HILLS	SPP	MSW	--	5/1987	C
COCA COLA	1	POLK	COG	NG	--	12/1987	NC
	2	POLK	COG	NG	--	12/1987	NC
GARDINIER	1	HILLS	COG	WH	--	8/1988	NC
CF INDUSTRIES	1	HILLS	COG	WH	--	12/1988	NC
FARMLAND	1	POLK	COG	WH	--	10/1990	NC

(1) INTERRUPTIBLE STANDBY CUSTOMER

UTILITY: TAMPA ELECTRIC COMPANY

EXISTING QUALIFYING FACILITIES
(AS OF OCTOBE[illegible], 1990)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				QF LOAD SERVED BY QF GENERATION (MW)		PLANT AUXILARY LOAD - MW		MAXIMUM NORMAL GENERATOR OUTPUT (MW)	
		FIRM		AS AVAILABLE							
FACILITY NAME	UNIT NO.	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
IMC (1)	1 - 2			1.8	1.8	58.5	58.5	--	--	60.3	60.3
CONSERV (1)		2.7	2.7	0.7	0.7	10.8	10.8	--	--	14.2	14.2
U.S.F.	1 - 2					1.7	1.7	--	--	1.7	1.7
NITRAM						2.6	2.6	--	--	2.6	2.6
CITY OF TAMPA REFUSE		15.5	15.5			2.3	2.3	--	--	17.8	17.8
ROYSTER (1)						12.0	12.0	--	--	12.0	12.0
SEMINOLE FERTILIZER				5.0	5.0	21.0	21.0	--	--	26.0	26.0
CITY SEWAGE (1)	1 - 5					2.5	2.5	--	--	2.5	2.5
HILLS. CTY REFUSE		23	23	3.8	3.8	2.8	2.8	--	--	29.6	29.6
COCA COLA						7.7	7.7	--	--	7.7	7.7
GARDINIER				1.4	1.4	34.6	34.6	--	--	36.0	36.0
CF INDUSTRIES				3.1	3.1	32.0	32.0	--	--	35.1	35.1
FARMLAND				8.0	8.0	26.0	26.0	--	--	34.0	34.0

NOTE: COLUMN (3) + (5) = COLUMN (11) - (9) - (7)
COLUMN (4) + (6) = COLUMN (12) - (10) - (8)

(1) INTERRUPTIBLE STANDBY CUSTOMER

UTILITY: TAMPA ELECTRIC COMPANY

PLANNED AND PROPOSED QUALIFYING FACILITIES
(AS OF OCTOBER 1, 1990)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				FUEL TYPE		COMMERCIAL IN-SERVICE	
FACILITY NAME	UNIT NO.	LOCATION	TYPE	PRIMARY	ALTERNATE	(MO/YR)	STATUS
SEMINOLE FERTILIZER	2	POLK	COG	WH	--	1/1992	NC
ST. JOSEPH	1	HILLS	COG	WH	--	1/1992	NC
LYKES PASCO	1	PASCO	COG	WH	--	1/1993	NC
MACDILL AFB	1	HILLS	COG	NG	--	1/1993	NC
REFUSE PLANT	1	UNK	SPP	MSW	--	1/1993	NC
GENERIC INDUSTRIAL	1	UNK	COG	WH	--	1/1994	NC
GENERIC COMMERCIAL	1	UNK	COG	WH	--	1/1995	NC
GENERIC HOSPITAL	1	UNK	COG	WH	--	1/1996	NC
GENERIC INDUSTRIAL	1	UNK	COG	WH	--	1/1997	NC
GENERIC COMMERCIAL	1	UNK	COG	WH	--	1/1998	NC
GENERIC HOSPITAL	1	UNK	COG	WH	--	1/1999	NC
GENERIC INDUSTRIAL	1	UNK	COG	WH	--	1/2000	NC

(1) INTERRUPTIBLE STANDBY CUSTOMER

UTILITY: TAMPA ELECTRIC COMPANY

PLANNED AND PROPOSED QUALIFYING FACILITIES
(AS OF OCTOBER 1, 1990)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				QF LOAD SERVED BY QF GENERATION (MW)		PLANT AUXILARY LOAD - MW		MAXIMUM NORMAL GENERATOR OUTPUT (MW)	
		FIRM		AS AVAILABLE							
FACILITY NAME	UNIT NO.	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
SEMINOLE FERTILIZER	2	17.0	17.0	0.8	0.8	20.2	20.2	--	--	38.0	38.0
ST. JOSEPH						2.5	2.5	--	--	2.5	2.5
LYKES PASCO				3.1	3.1	32.0	32.0	--	--	35.1	35.1
MACDILL AFB						11.0	11.0	--	--	11.0	11.0
REFUSE PLANT		8.0	8.0			1.0	1.0	--	--	9.0	9.0
GENERIC INDUSTRIAL						5.0	5.0	--	--	5.0	5.0
GENERIC COMMERIAL						3.0	3.0	--	--	3.0	3.0
GENERIC HOSPITAL						3.0	3.0	--	--	3.0	3.0
GENERIC INDUSTRIAL						3.0	3.0	--	--	3.0	3.0
GENERIC COMMERIAL						3.0	3.0	--	--	3.0	3.0
GENERIC HOSPITAL						3.0	3.0	--	--	3.0	3.0
GENERIC INDUSTRIAL						3.0	3.0	--	--	3.0	3.0

NOTE: COLUMN (3) + (5) = COLUMN (11) - (9) - (7)
COLUMN (4) + (6) = COLUMN (12) - (10) - (8)

(1) INTERRUPTIBLE STANDBY CUSTOMER

UTILITY: TAMPA ELECTRIC COMPANY

SUMMARY OF FIRM ENERGY AND CAPACITY CONTRACTS WITH QUALIFYING FACILITIES AS OF OCTOBER 1, 1990

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	CONTRACT TERM		CONTRACT CAPACITY		CONTRACT ENERGY			AVOIDED UNIT			
QUALIFYING FACILITY	FROM MO/YR	TO MO/YR	NET SUM. (MW)	NET WIN. (MW)	GWH	% CAP. FACTOR	BILLING METHOD	NAME	ANTICIPATED IN-SERVICE (MO/YR)	NET SUMMER CAPABILITY (MW)	NOTES
PURCHASING UTILITY: TEC											
CONSERV	12/1982	12/1992	2.7	2.7	30	127%	NET	N/A	N/A	N/A	
CITY OF TAMPA	06/1985	03/2009	15.5	15.5	112.8	83%	NET	N/A	N/A	N/A	
HILLS. CTY REFUSE	04/1987	03/2010	23	23	216	107%	NET	GENERIC STATE WIDE AVOIDED UNIT	04/92	2-700	STANDAR OFFER

NOTE: INDICATE IN COLUMN (12) THE LOCATION OF THE QF AND THE WHEELING UTILITY, IF THE POWER IS BEING WHEELED THROUGH ANOTHER UTILITY.

UTILITY: TAMPA ELECTRIC COMPANY

HISTORY AND FORECAST OF ENERGY AND CAPACITY PURCHASES FROM QUALIFYING FACILITIES AS OF OCTOBER 1, 1988

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
					NET TO GRID		
YEAR	NET TO GRID SUMMER CAPACITY (MW)	YEAR	NET TO GRID WINTER CAPACITY (MW)	YEAR	FIRM ENERGY (GWH)	AS-AVAILABLE ENERGY (GWH)	TOTAL ENERGY (GWH)
ACTUAL:		ACTUAL:		ACTUAL:			
1988	48.3	1987 / 88	48.3	1988	357.1	62.6	419.7
1989	43.2	1988 / 89	43.2	1989	357.3	21.1	378.4
FORECAST:		FORECAST:		FORECAST:			
1990	41.2	1989 / 90	41.2	1990	358.1	60.3	418.4
1991	58.2	1990 / 91	58.2	1991	358.1	60.3	418.4
1992	63.5	1991 / 92	63.5	1992	359.1	191.3	550.4
1993	67.5	1992 / 93	67.5	1993	397.9	202.6	600.5
1994	67.5	1993 / 94	67.5	1994	428.3	202.6	630.9
1995	67.5	1994 / 95	67.5	1995	428.3	202.6	630.9
1996	67.5	1995 / 96	67.5	1996	429.5	203.1	632.6
1997	67.5	1996 / 97	67.5	1997	428.3	202.6	630.9
1998	67.5	1997 / 98	67.5	1998	428.3	202.6	630.9
1999	67.5	1998 / 99	67.5	1999	428.3	202.6	630.9
2000	67.5	1999 / 0	67.5	2000	429.5	203.1	632.6

NOTE: COL (2) IS THE CUMULATIVE SUM OF COLS (3) AND (5) OF PAGES A17 AND A19, BY YEAR .
COL (4) IS THE CUMULATIVE SUM OF COLS (4) AND (6) OF PAGES A17 AND A19, BY YEAR .
COLS (6) AND (7) SHOULD BE THE ENERGY WHICH UTILITIES EXPECT TO RECEIVE FROM THE QF'S REPORTED IN PAGES A17 AND A19, RESPECTIVELY.

UTILITY: TAMPA ELECTRIC COMPANY

FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - GWH

		---ACTUAL---		ACT/EST 9/90									
		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
INTERCHANGE	GWH	(1,681)	(813)	(625)	(1,057)	(1,152)	(1,215)	(1,035)	(964)	(874)	(790)	(718)	(639)
NUCLEAR	GWH	0	0	0	0	0	0	0	0	0	0	0	0
COAL	GWH	16,352	16,237	15,718	17,079	17,446	17,253	17,666	17,664	18,199	18,275	18,227	18,360
HO-TOTAL	GWH	0	0	0	128	144	72	68	84	76	38	50	60
STEAM	GWH	0	0	0	128	144	72	68	84	76	38	50	60
CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0
LO-TOTAL	GWH	27	46	68	38	44	16	17	53	77	10	38	76
STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CT	GWH	27	46	68	38	44	16	17	53	77	10	38	76
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0
NG-TOTAL	GWH	0	0	0	0	0	0	0	0	0	338	421	470
STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CC	GWH	0	0	0	0	0	0	0	0	0	338	421	470
CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0
ALT-TOTAL	GWH	0	0	0	0	0	0	0	0	0	0	0	0
STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0
HYDRO	GWH	0	0	0	0	0	0	0	0	0	0	0	0
COGEN & SPP	GWH	419	378	338	418	550	601	631	631	633	631	631	631
OTHER	GWH	(2,219)	(2,186)	(1,724)	(2,384)	(2,565)	(2,061)	(2,266)	(2,036)	(2,251)	(2,072)	(1,862)	(1,799)
NEL	GWH	12,898	13,662	13,775	14,222	14,467	14,666	15,081	15,432	15,860	16,430	16,787	17,159

NOTE: ALT FUEL INCLUDES ONE OR A COMBINATION OF THE FOLLOWING FUELS: A) RESIDUAL OIL, B) NATURAL GAS, C)COAL GAS, D) COAL LIQUIFICATION PRODUCTS, E) COAL (WHERE APPLICABLE), OR F) OTHER APPROPRIATE FUEL. CONSUMPTION WOULD DEPEND ON RELATIVE FUEL ECONOMICS.

UTILITY: TAMPA ELECTRIC COMPANY

HISTORY AND FORECAST: FUEL REQUIREMENTS

		---ACTUAL---		ACT/EST 9/90									
		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
NUCLEAR	10E3 BTU	0	0	0	0	0	0	0	0	0	0	0	0
COAL	10E3 TON	6,884	6,759	6,531	7,020	7,152	7,185	7,344	7,348	7,565	7,570	7,575	7,609
HO-TOTAL	10E3 BBL	0	0	0	275	309	155	147	183	166	83	112	136
STEAM	10E3 BBL	0	0	0	275	309	155	147	183	166	83	112	136
CC	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
CT	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
LO-TOTAL	10E3 BBL	73	124	179	91	106	39	41	75	87	23	51	88
STEAM	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
CC	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
CT	10E3 BBL	73	124	179	91	106	39	41	75	87	23	51	88
DIESEL	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0
NG-TOTAL	10E6 CF	0	0	0	0	0	0	0	0	0	2,689	3,353	3,736
STEAM	10E6 CF	0	0	0	0	0	0	0	0	0	0	0	0
CC	10E6 CF	0	0	0	0	0	0	0	0	0	2,689	3,353	3,736
CT	10E6 CF	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	10E6 CF	0	0	0	0	0	0	0	0	0	0	0	0
ALT-TOTAL	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0
STEAM	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0
CC	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0
CT	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0
OTHER		0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL AVG NET FOSSIL HR BTU/KWH		10,090	10,167	10,108	10,172	10,173	10,162	10,155	10,159	10,148	10,109	10,102	10,106

NOTE: ALT FUEL INCLUDES ONE OR A COMBINATION OF THE FOLLOWING FUELS: A) RESIDUAL OIL, B) NATURAL GAS, C) COAL GAS, D) COAL LIQUIFICATION PRODUCTS, E) COAL (WHERE APPLICABLE), OR F) OTHER APPROPRIATE FUEL. CONSUMPTION WOULD DEPEND ON RELATIVE FUEL ECONOMICS.

INDEX

COGENERATION AND SMALL POWER PRODUCTION

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM
QUALIFYING COGENERATION AND SMALL POWER
PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE
COG-1, As-Available Energy

AVAILABLE
Tampa Electric Company will purchase energy offered by any Qualifying Facility irrespective of its location, which is directly or indirectly interconnected with the Company, under the provisions of this schedule or at contract negotiated rates. Tampa Electric Company will negotiate and may contract with a Qualifying Facility, irrespective of its location, which is directly or indirectly interconnected with the Company where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE
To any cogeneration or small power production Qualifying Facility producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by the Florida Public Service Commission (FPSC) Rule 25-17.0825, Florida Adminstrative Code (F.A.C.), and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required. Because of the lack of assurance as to the quantity, time, or reliability of delivery of As-Available Energy, no Capacity Payment shall be made to a Qualifying Facility for delivery of As-Available Energy. Criteria for achieving Qualifying Facility status shall be those set out in FPSC Rule 25-17.080.

CHARACTER OF SERVICE
Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering As-Available Energy from the Qualifying Facility.

LIMITATIONS
All service pursuant to this schedule is subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

RATES FOR PURCHASES BY THE COMPANY

A. Capacity Rates

Capacity payments to Qualifying Facilities will not be paid under this schedule. Capacity payments to small Qualifying Facilities of less than 75 MWs or Solid Waste Facilities may be obtained under a Standard Offer Contract as described in Schedule COG-2, Firm Capacity and Energy.

B. Energy Rates

As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour (¢/KWH), based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Customer charges directly attributable to the purchase of As-Available Energy from the Qualifying Facility are deducted from the Qualifying Facility's total monthly energy payment.

Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage. The calculation of payments to the Qualifying Facility shall be based on the sum, over all hours of the billing period, of the product of the hours avoided energy cost times the energy purchases from the Qualifying Facility by the Company for that hour. All sales shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy cost is described in Appendix A.

C. Negotiated Rates

Upon agreement by both the Company and the Qualifying Facility, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental avoided energy costs for the next four semi-annual periods are as follows. These estimates include a credit for variable operating and maintenance expenses. For the current six month period, October 1, 1990 - March 31, 1991, this credit is estimated to average 0.126¢/KWH. A Standard Tariff block will be used to calculate the actual hourly avoided energy cost as described in Appendix A.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly avoided energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0737
GSD, GSLD, SBF	1.0555
IS-1, IS-3, SBI-1, SBI-3	1.0250

METERING REQUIREMENTS

The Qualifying Facility within the territory served by the Company shall be required to purchase from the Company the metering equipment necessary to measure its energy deliveries to the Company. Energy purchased from Qualifying Facilities outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering As-Available Energy to the Company.

Hourly recording meters shall be required for Qualifying Facilities with an installed capacity of 100 kilowatts or more. Where the installed capacity is less than 100 kilowatts, the Qualifying Facility may select any one of the following options: **(a)** an hourly recording meter, **(b)** a dual kilowatt-hour register time-of-day meter, or **(c)** a standard kilowatt-hour meter.

For Qualifying Facilities with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on the product of: **(1)** the Company's actual avoided energy rate for each hour during the month; and **(2)** the quantity of energy sold by the Qualifying Facility during that hour.

For Qualifying Facilities with dual kilowatt-hour register time-of-day meters, monthly payments for As-Available Energy shall be calculated based on the product of: **(1)** the average of the Company's actual hourly avoided energy rates for the on-peak and off-peak periods during the month; and **(2)** the quantity of energy sold by the Qualifying Facility during that period.

For Qualifying Facilities with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly avoided energy rate for the off-peak periods during that month; and (2) the quantity of energy sold by the Qualifying Facility during that month.

For a time-of-day metered Qualifying Facility, the on-peak hours occur Monday through Friday except holidays, April 1 - October 31 from 12 noon to 9:00 p.m. and November 1 - March 31 from 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.. All hours not mentioned above and all hours of the holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

BILLING OPTIONS

The Qualifying Facilities may elect to make either simultaneous purchases and sales or net sales. The billing option elected may only be changed in accordance with FPSC Rule 25-17.082:

1. when the Qualifying Facility selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or

2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the Qualifying Facility or Tampa Electric Company; or

3. when the Qualifying Facility is selling As-Available Energy and has not changed billing methods within the last twelve months; and

4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the Qualifying Facility and Tampa Electric Company.

If the Qualifying Facility elects to change billing methods in accordance with FPSC Rule 25-17.082, such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice;

2. upon the installation by Tampa Electric Company of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such metering equipment and its installation; and

3. upon completion and approval by Tampa Electric Company of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such alterations.

Should a Qualifying Facility elect to make simultaneous purchases and sales, purchases of electric service by the Qualifying Facility from the interconnecting utility shall be billed at the retail rate schedule under which the Qualifying Facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the Qualifying Facility to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

Should a Qualifying Facility elect a net billing arrangement, the hourly net energy sales delivered to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832, purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

A statement covering the charges and payments due the Qualifying Facility is rendered monthly, and payment normally is made by the twentieth business day following the end of the billing period.

CHARGES TO QUALIFYING FACILITY

A. **Customer Charges**
Monthly customer charges for meter reading, billing and other applicable administrative costs by Rate Schedule are:

RS	$ 7.00	RST	$ 10.00
GS	7.00	GST	10.00
GSD	35.00	GSDT	42.00
GSLD	170.00	GSLDT	170.00
SBF	195.00	SBFT	195.00
IS-1	670.00	IST-1	670.00
IS-3	710.00	IST-3	710.00
SBI-1	695.00	SBIT-1	695.00
SBI-3	735.00	SBIT-3	735.00

B. **Interconnection Charge for Non-Variable Utility Expenses:**
The Qualifying Facility shall bear the cost required for interconnection including the metering. The Qualifying Facility shall have the option of payment in full for interconnection or making equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

C. **Interconnection Charge for Variable Utility Expenses**
The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include: (a) the Company's inspections of the interconnection and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company are involved.

D. Taxes and Assessments
The Qualifying Facility shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility.

TERMS OF SERVICE

1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in its electric generation capability.

2) Any electric service delivered by the Company to the Qualifying Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

   A) In the first year of operation, the security deposit shall be based upon the singular month in which the Qualifying Facility's projected purchases from the utilty exceed, by the greatest amount, the utility's estimated purchases from the Qualifying Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon interconnection.

   B) For each year thereafter, a review of the actual sales and purchases between the Qualifying Facility and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Qualifying Facility exceed the actual sales to the utility in that month.

4) The company shall specify the point of interconnection and voltage level.

5) The Company will, under the provisions of this schedule, require an interconnection agreement with the Qualifying Facility using the Company's filed Interconnection Agreement. The Qualifying Facility shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated, and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6) Service under this rate schedule is subject to the rules and regulations of the Company and the Florida Public Service Commission.

SPECIAL PROVISIONS

1) Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the Florida Public Service Commission.

2) In accordance with the provision in Rule 25-17.0883, the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charge, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers.

A determination of whether or not transmission service for self-service wheeling is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3) In accordance with Rule 25-17.089, upon request by a Qualifying Facility, Tampa Electric Company shall provide transmission service to wheel As-Available Energy produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

4) Where existing Company transmission capacity exists, the Company will impose a charge for wheeling Qualifying Facility energy, measured at the point of delivery to the Company. The rates, terms, and conditions for such transmission service shall be those approved by the Federal Energy Regulatory Commission.

5) The Company's actual rates for providing transmission service will be determined on an individually negotiated case-by-case basis in order to allow for variations in providing such service under different circumstances. The Company will provide, upon request, estimates of the availability and cost and terms and conditions of providing the specified desired transmission wheeling service.

6) The Qualifying Facility shall be responsible for all costs associated with such wheeling and the Company will deduct such costs from payments to the Qualifying Facility including:

   a) Wheeling charges
   b) Line losses incurred by the Company
   c) Inadvertent energy flows resulting from such wheeling.

7) Energy delivered to the Company shall be adjusted before delivery to another utility as follows:

Qualifying Facility Rate Schedule	Adjustment Factor
RS, GS	0.9313
GSD, GSLD, SBF	0.9474
IS-1, IS-3, SBI-1, SBI-3	0.9756

8) The Company may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non-discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the Company's general body of retail and wholesale customers.

METHODOLOGY TO BE USED IN THE CALCULATION OF AVOIDED ENERGY COST SCHEDULE COG-1 APPENDIX A

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum spinning reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

The as-available avoided energy cost, as determined by this methodology, is priced at a level not to exceed Tampa Electric's incremental fuel and identifiable variable operating and maintenance (O&M) expenses plus the cost of any off-system purchases for native load.

Parameters For Determining As-Available Avoided Energy Costs

Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of Tampa Electric's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor, and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (4. above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

Supplemental Fuel

The term "supplemental fuel" refers to that fuel purchased in excess of Tampa Electric's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for Tampa Electric to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. Tampa Electric pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, Tampa Electric treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

Avoid Energy Cost Calculations

Example: #1 No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation of all QFs making as-available energy sales to Tampa Electric. In the absence of metered information, Tampa Electric's best estimate of the hourly as-available generation will be used rounded to the nearest 5 MWs. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the Avoided Energy Rate (AER) for the hour. The AER will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Example #2 Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit #6. (Example #3)

Line Loss Credit

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental hourly avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to Tampa Electric would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M

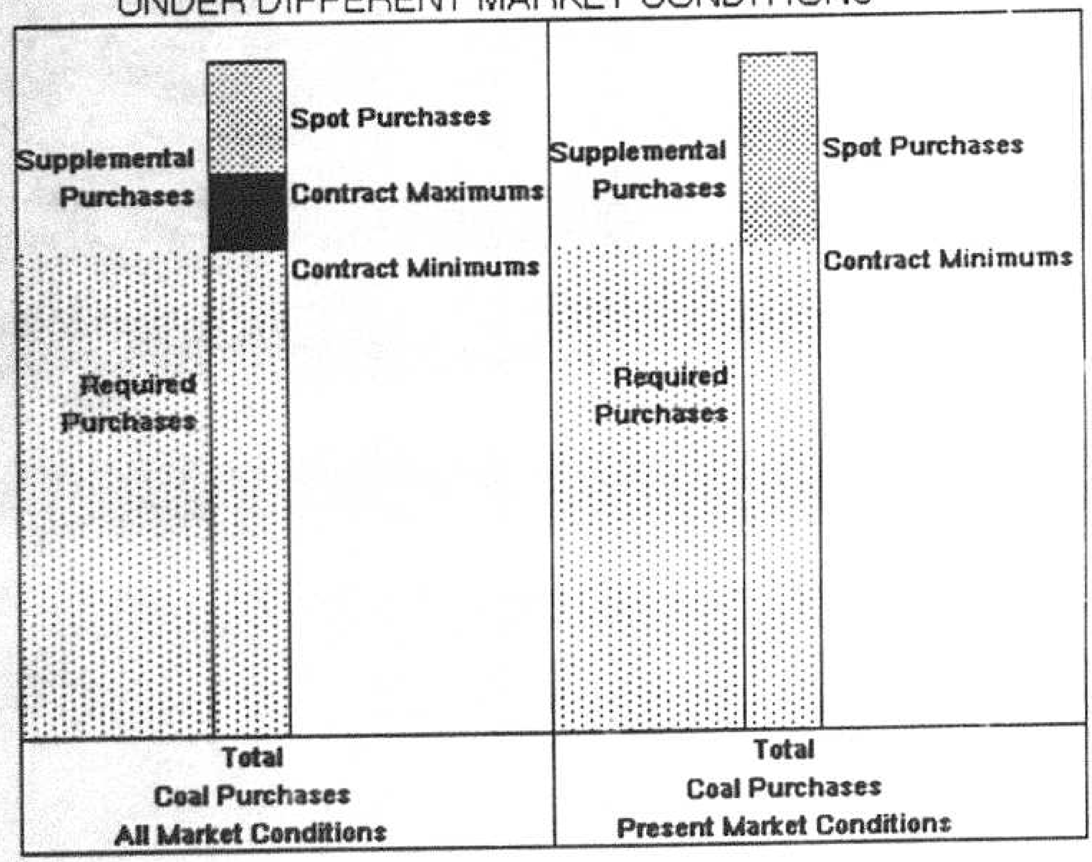
A procedure for approximating the "identifiable" incremental variable O&M expenses is included in Tampa Electric's methodology for the determination of incremental avoided energy costs associated with as-available energy.

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute, was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information.
Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7).

EXHIBIT #1

REQUIRED AND SUPPLEMENTAL COAL PURCHASES
UNDER DIFFERENT MARKET CONDITIONS



TAMPA ELECTRIC COMPANY

ORIGINAL SHEET NO. 8.107

EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENTAL FUEL COST
Gannon 1-4	A				$45.30			177.50
Gannon 5 & 6	B				$45.48			176.44
Big Bend 1 & 2	C				$29.22			123.13
	D				$31.67			
	E				$32.08			
				Average	$29.87			
Big Bend 3[1]	F				$50.55			173.67
				Blended Average	$42.28			
Big Bend 4	G				$41.70			181.31
	H				$37.21			
				Average	$41.11			
#2 Oil	I				$19.41/BBL			334.64

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

ISSUED BY: G.F. Anderson, President

DATE EFFECTIVE

EXHIBIT #3

Example #1 No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):

Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):

Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):

Actual Hourly Avoided Energy Cost =

($20,275/Hour - $19,500/Hour) / (50MW)

or

Avoided Energy Rate (AER) = $15.50/MWH

EXHIBIT #4

Example #2a Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:
Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:
Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) =
($18,900/Hour - $18,882.50/Hour) / (1 MW)

or

Avoided Energy Rate (AER) = $17.50/MWH

NOTE: [1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

TAMPA ELECTRIC COMPANY

RESERVED FOR FUTURE USE

EXHIBIT #5

Example #2b Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1530 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)
First Calculation ("WITHOUT" QF):
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation ("With" QF):
Production Cost at 1500 MWs = $20,050/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)
First Calculation:
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) for 20 MWs =
($20,590/Hour - $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)
Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
$540 + $370 / 50 MW

or

Avoided Energy Rate (AER) = $18.20/MWH

NOTE:
1 In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

EXHIBIT #6

Example #3 Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases[1] = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AER = $40/Hour

NOTES: [1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the Technical Assessment Guide dated May 1982, published by the Electric Power Research Institute (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:		1983 TEC Coal Generation	MW	
1) Big Bend	1		367	
	2		362	
	3		375	
	3		10	upgrade
Gannon	5		218	
	6		351	
	4		169	conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor $= \frac{10,493,266}{15,050,712} \times 100\%$

$= 69.72\%$

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] $= \frac{10,694,772}{10,493,266} = \$1.02/\text{MWH}$

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR SOLID WASTE FACILITIES (QUALIFYING FACILITIES)

SCHEDULE
COG-2, Firm Capacity and Energy

AVAILABLE
Tampa Electric Company will purchase Firm Capacity and Energy offered by any Qualifying Facility of less than 75 MWs or Solid Waste Facility, irrespective of its location, which is either directly or indirectly interconnected with the Company under the provisions of this schedule. On September 18, 1990, the Florida Public Service Commission ordered Tampa Electric Company to designate an Avoided Unit associated with Tampa Electric's Standard Offer Contract. Tampa Electric Company's next Designated Avoided Unit is a 75 MW oil/natural gas fired Combustion Turbine (CT) generating unit with an in-service date of January 1, 1996. Each year by January 1, the Company will complete the assessment of need for additional Firm Capacity and Energy Purchases for the next calendar year. Until such time as the Designated Avoided Unit subscription limits have been exceeded, the Company will subscribe Firm Capacity and Energy offered by any Qualifying Facility or Solid Waste Facility under the provisions of this schedule.

Tampa Electric Company will negotiate and may contract with any Qualifying Facility, irrespective of its location, which is either directly or indirectly interconnected with the Company for the purchase of Firm Capacity and Energy pursuant to terms and conditions which deviate from this schedule where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE
To any cogeneration or small power production Qualifying Facility of less than 75 MWs or Solid Waste Facility, irrespective of its location, producing capacity and energy for sale to the Company on a firm basis pursuant to the terms and conditions of this schedule and the Company's "Standard Offer Contract" or a separately negotiated contract. Firm Capacity and Energy are described by the Florida Public Service Commission (FPSC) Rule 25-17.0832, Florida Administrative Code (F.A.C.), and are capacity and energy produced and sold by a Qualifying Facility or Solid Waste Facility pursuant to a negotiated or standard Company contract offer and subject to certain contractual provisions as to quantity, time and reliability of delivery. Criteria for achieving Qualifying Facility or Solid Waste Facility status shall be those set out in FPSC Rule 25-17.080, F.A.C.

CHARACTER OF SERVICE
Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 Hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering Firm Capacity and Energy from the Qualifying Facility or Solid Waste Facility.

LIMITATIONS
Purchases under this schedule are subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C. and are limited to those small Qualifying Facilities of less than 75 MWs or Solid Waste Facilities which:

A) Execute a Company "Standard Offer Contract" prior to January 1, 1994 for the Company's purchase of Firm Capacity and Energy; and
B) Commit to commence deliveries of Firm Capacity and Energy no later than January 1, 1996 and to continue such deliveries through at least December 31, 2005.
C) Provide capacity which would not result in the 75 MW subscription limit on capacity as approved by the FPSC on September 18, 1990, to be exceeded.

RATES FOR PURCHASES BY THE COMPANY
Firm Capacity and Energy are purchased at unit costs, in dollars per kilowatt per month and cents per kilowatt hour, respectively, based on the value of deferring additional Tampa Electric Company generating capacity. For the purpose of this schedule, the Avoided Unit has been designated by Tampa Electric as a peaking generating plant consisting of one (1), 75 MW oil/natural gas fired Combustion Turbine generating unit with an in-service date of January 1, 1996. Appendix A of this schedule describes the methodology used to calculate payment schedules, general terms, and conditions applicable to the Company's "Standard Offer Contract" pursuant to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

A. Firm Capacity Rates

Four options, 1, 2, 3, and 4, as set forth below, are available for payment of Firm Capacity which is produced by the Qualifying Facility or Solid Waste Facility and delivered to the Company. Once selected, an option shall remain in effect for the term of the contract with the Company. Exemplary payment schedules, shown on sheets following this section, contain the monthly rate per kilowatt of Firm Capacity the Qualifying Facility or Solid Waste Facility has contractually committed to deliver to the Company and are based on a minimum contract term which extends ten (10) years beyond the anticipated in-service date of the Designated Avoided Unit (i.e., through December 31, 2005). Payment schedules for longer contract terms will be made available to a Qualifying Facility or Solid Waste Facility upon request and may be calculated based on the methodologies described in Appendix A. At a maximum, Firm Capacity and Energy shall be delivered for a period of time equal to the anticipated plant life of the Designated Avoided Unit, commencing with the anticipated in-service date of the Designated Avoided Unit.

Option 1 - Value of Deferral Capacity Payments - Value of Deferral Capacity Payments shall commence on January 1, 1996, the anticipated in-service date of the Designated Avoided Unit, provided the Qualifying Facility or Solid Waste Facility is delivering Firm Capacity and Energy to the Company. Capacity payments under this option shall consist of monthly payments escalating annually of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit and shall be equal to the value of the year-by-year deferral of the Designated Avoided Unit, calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A.

Option 2 - Early Capacity Payments - Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 1996. The earliest date that Early Capacity Payments can be received by a Qualifying Facility or Solid Waste Facility shall be January 1, 1994. This is an approximation of the lead time required to site and construct the Designated Avoided unit. The Qualifying Facility or Solid Waste Facility shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Early Capacity Payments shall consist of monthly payments escalating annually of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit. Avoided capacity payments shall be calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. At the option of the Qualifying Facility or Solid Waste Facility, Early Capacity Payments may commence at any time after the specified earliest capacity payment date and before the anticipated in-service date of the Designated Avoided Unit provided the Qualifying Facility of Solid Waste Facility is delivering Firm Capacity and Energy to the Company. Where Early Capacity Payments are elected, the cumulative present value of the capacity paid to the Qualifying Facility or Solid Waste Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Qualifying Facility or Solid Waste Facility had such payments been made pursuant to Option 1.

Option 3 - Levelized Capacity Payments - Levelized Capacity Payments shall commence on the anticipated in-service date of the Designated Avoided Unit, provided the Qualifying Facility or Solid Waste Facility is delivering Firm Capacity and Energy to the Company. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance portion of the capacity payment shall be equal to the value of the year-by-year deferral of fixed operation and maintenance associated with the Designated Avoided Unit calculated in conformance with Appendix A. Where Levelized Capacity Payments are elected, the cumulative present value of the capacity paid to the Qualifying Facility or Solid Waste Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Qualifying Facility or Solid Waste Facility had such payment been made pursuant to Option 1.

Option 4 - Early Levelized Capacity Payments - Early Levelized Capacity Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 1996. The earliest date that Early Levelized Capacity Payments can be received by a Qualifying Facility or Solid Waste Facility shall be January 1, 1994. This is an approximation of the lead time required to site and construct the Designated Avoided Unit. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with the FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance portion of the capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance associated with the Designated Avoided Unit calculated in conformance with Appendix A. At the option of the Qualifying Facility or Solid Waste Facility, Early Levelized Capacity Payments shall commence at any time after the specified earliest capacity payment date and before the anticipated in-service date of the Designated Avoided Unit provided the Qualifying Facility or solid Waste Facility is delivering Firm Capacity and Energy to the Company. The Qualifying Facility or Solid Waste Facility shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Where Early Levelized Capacity Payments are elected, the cumulative present value of the capacity payments paid to the Qualifying Facility or Solid Waste Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Qualifying Facility or Solid Waste Facility had such payments been made pursuant to Option 1.

TAMPA ELECTRIC COMPANY

The Company will provide the Qualifying Facility or Solid Waste Facility with a schedule of capacity payment rates based on the month and year in which the delivery of Firm Capacity and Energy are to commence and the term of the contract. The following exemplary payment schedules are based on the minimum required contract term which must extend at least ten (10) years beyond the anticipated in-service date of the Designated Avoided Unit. The currently approved parameters used to calculate the following schedule of payments are found in Appendix B of this schedule.

UNIT TYPE: 75 MW COMBUSTION TURBINE (IN-SERVICE 1996)
MONTHLY CAPACITY PAYMENT RATE $/KW/MONTH

CONTRACT YEAR		OPTION 1 NORMAL PAYMENT STARTING	OPTION 2 EARLY PAYMENT STARTING		OPTION 3 LEVELIZED PAYMENT STARTING	OPTION 4 EARLY LEVELIZED PAYMENT STARTING	
FROM	TO	1/1/96 $/KW/MO	1/1/95 $/KW/MO	1/1/94 $/KW/MO	1/1/96 $/KW/MO	1/1/95 $/KW/MO	1/1/94 $/KW/MO
1/1/94	12/31/94	-	-	3.54	-	-	4.45
1/1/95	12/31/95	-	4.16	3.72	-	5.13	4.45
1/1/96	12/31/96	4.93	4.37	3.91	5.97	5.14	4.45
1/1/97	12/31/97	5.18	4.59	4.11	5.97	5.14	4.46
1/1/98	12/31/98	5.44	4.84	4.32	5.98	5.14	4.46
1/1/99	12/31/99	5.72	5.07	4.54	5.98	5.15	4.47
1/1/00	12/31/00	6.01	5.33	4.77	5.99	5.15	4.47
1/1/01	12/31/01	6.31	5.60	5.01	5.99	5.16	4.47
1/1/02	12/31/02	6.64	5.89	5.27	6.00	5.16	4.48
1/1/03	12/31/03	6.97	6.19	5.53	6.01	5.17	4.48
1/1/04	12/31/04	7.33	6.50	5.82	6.01	5.18	4.49
1/1/05	12/31/05	7.70	6.83	6.11	6.02	5.18	4.49

ISSUED BY: G.F. Anderson, President

DATE EFFECTIVE:

TAMPA ELECTRIC COMPANY

RESERVED FOR FUTURE USE

TAMPA ELECTRIC COMPANY

RESERVED FOR FUTURE USE

B. Energy Rates

1) **Payments Prior to January 1, 1996:** The energy rate in cents per kilowatt-hour (¢/KWH) shall be based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage.

The calculation of payments to the Qualifying Facility or Solid Waste Facility shall be based on the sum, over all hours of the billing period, of the product of each hour's avoided energy cost times the energy purchased from the Qualifying Facility or Solid Waste Facility by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

2) **Payments Starting on January 1, 1996:** The firm energy rate in cents per kilowatt hour (¢/KWH) shall be based on the Designated Avoided Unit's energy cost (fuel and variable operation & maintenance expense), to the extent that the Designated Avoided Unit would have operated had it been installed by Tampa Electric. Otherwise, the avoided energy payments to the Qualifying Facility or Solid Waste Facility will be based on Tampa Electric's actual avoided energy cost.

Calculation of payments to the Qualifying Facility or Solid Waste Facility shall be based on the sum, over all hours of the billing period, of the product of each hour's avoided energy cost times the energy purchased from the Qualifying Facility or Solid Waste Facility by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

ESTIMATED FIRM ENERGY COST

For informational purposes only, the estimated incremental avoided energy costs for the next four semi-annual periods are as follows. These estimates include a credit for variable operating and maintenance expenses. For the current six month period, October 1, 1990 - March 31, 1991, this credit is estimated to average 0.126¢/KWH. A Standard Tariff block will be used to calculate the actual hourly avoided energy cost as described in Appendix D.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 1990 - March 31, 1991	2.268	2.000	2.080
April 1, 1991 - September 30, 1991	3.450	3.026	3.163
October 1, 1991 - March 31, 1992	2.688	2.356	2.450
April 1, 1992 - September 30, 1992	4.944	4.337	4.533

For informational purposes the Company's 10 year projected annual generation mix and fuel prices are as follows:

	Percent Generation by Fuel Type			Supplemental Price of Fuel Delivered		
Year (¢/MBTU)	#2 Oil	#6 Oil	Coal	#2 Oil (¢/MBTU)	#6 Oil (¢/MBTU)	Coal
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1990	0.2	0.0	99.8	434	313	161
1991	0.3	0.0	99.7	489	362	170
1992	0.4	0.4	99.2	712	513	182
1993	0.2	0.4	99.4	737	541	197
1994	0.3	0.4	99.3	809	591	209
1995	0.3	1.1	98.6	872	646	221
1996	0.3	1.3	98.4	955	703	233
1997	0.5	1.5	98.0	1045	761	247
1998	0.9	1.8	97.3	1135	827	262
1999	1.3	1.9	96.8	1232	895	275

"Supplemental" refers to fuel purchases in excess of long-term contract minimum requirements.

The estimated average fuel costs associated with the Designated Avoided Unit during those hours in which it is expected to be dispatched are as follows:

¢/KWH

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
10.729	11.081	12.249	13.315	15.707	16.929	18.715	21.919	25.047	27.499

The estimated weighted average avoided firm energy (fuel) costs associated with the Designated Avoided Unit during all hours of the year are as follows:

¢/KWH

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
3.054	3.506	3.835	4.256	5.332	3.844	4.388	4.596	4.911	6.383

PERFORMANCE CRITERIA

In addition to the following provisions, payments for Firm Capacity are conditioned on the Qualifying Facility's or Solid Waste Facility's ability to meet or exceed the Minimum Performance Standards (MPS) for Tampa Electric's Designated Avoided Unit as described in Appendix C:

A) **Commercial In-Service Date**

Capacity Payments shall not commence until the Qualifying Facility or Solid Waste Facility has attained and demonstrated commercial in-service status. The commercial in-service date of a Qualifying Facility or Solid Waste Facility shall be defined as the first day of the month following the successful completion of the Qualifying Facility or Solid Waste Facility maintaining an hourly kilowatt (KW) output, as metered at the point of interconnection with the Company, equal to or greater than the Qualifying Facility's or Solid Waste Facility's "Standard Offer Contract" committed capacity for a 24 hour period. A Qualifying Facility or Solid Waste Facility shall coordinate the operation of its facility during this test period with the Company to insure that the performance of its facility during this 24 hour period is reflective of the anticipated day to day operation of the Qualifying Facility or Solid Waste Facility.

B) **Availability and Capacity Factor**

Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly in accordance with the capacity payment rate option selected by the Qualifying Facility or Solid Waste Facility and subject to the provision that the Qualifying Facility or Solid Waste Facility equals or exceeds the Minimum Performance Standards (MPS) for peak and off-peak availability and capacity factor of Tampa Electric's Designated Avoided Unit, on a 12 month rolling average basis, as defined in Appendix C

To ensure that Tampa Electric will receive a capacity benefit for which Early, Levelized, or Early Levelized Capacity Payments have been made, or alternatively, that the Qualifying Facility or Solid Waste Facility will repay the amount of early payments received to the extent the capacity benefit has not been conferred, the following provisions will apply:

All capacity payments made by the Company prior to January 1, 1996 are considered "early payments". Similarly Levelized and Early Levelized Capacity Payments for capacity delivered after January 1, 1996, may also exceed the year-by-year value of deferring the Designated Avoided Unit, and these excess amounts are also in the nature of "early payments" for a future capacity benefit to Tampa Electric.

Tampa Electric shall establish a Capacity Account. Amounts shall be credited to the Capacity Account in the amount of Tampa Electric's early payments made to the Qualifying Facility or Solid Waste Facility pursuant to the Qualifying Facility's or Solid Waste Facility's chosen payment option.

Where Early Capacity Payments, Levelized Capacity Payments, or Early Levelized Capacity Payments have been selected, failure to meet the MPS shall result in the Qualifying Facility's or Solid Waste Facility's forfeiture of payments for Firm Capacity during the month in which such failure occurs.

In addition, at such time that the monthly capacity payment made to the Qualifying Facility or Solid Waste Facility, pursuant to the capacity payment option selected, is less than the normal monthly capacity payment the Qualifying Facility or Solid Waste Facility would have received if it had selected the normal payment Option 1, beginning January 1, 1996, failure to meet the MPS shall result in payments by the Qualifying Facility or Solid Waste Facility to the Company. The amount of such payments shall be equal to the difference between: 1) what the Qualifying Facility or Solid Waste Facility would have been paid had it elected the normal payment option starting January 1, 1996; and 2) what it would have been paid pursuant to the Early Capacity Payment, Levelized Capacity Payment, or Early Levelized Capacity Payment option had it met the MPS performance criteria. Such repayments shall be debited from the Capacity Account as an Early Payment Offset Amount and will not exceed the current balance in the Capacity Account.

Beginning on January 1, 1996, the difference between the capacity payment made to the Qualifying Facility or Solid Waste Facility and the "normal" capacity payment calculated pursuant to Option 1 will also be credited each month to the capacity account, so long as the payment to the Qualifying Facility or Solid Waste Facility is greater than the monthly payment the Qualifying Facility or Solid Waste Facility would have received if it had selected Option 1.

At such time that the monthly capacity payment made to the Qualifying Facility or Solid Waste Facility pursuant to the Payment Option selected, is less than the normal monthly capacity payment in Option 1, there shall be debited from the Capacity Account an Early Payment Offset Amount to reduce the balance in the Capacity Account. Such Early Payment Offset Amount shall be equal to the amount which Tampa Electric would have paid for capacity in that month if capacity payment had been calculated pursuant to Option 1 and the Qualifying Facility or Solid Waste Facility had elected to begin receiving payment on January 1, 1996 minus the monthly capacity payment Tampa Electric makes to the Qualifying Facility or Solid Waste Facility pursuant to the capacity option chosen by the Qualifying Facility or Solid Waste Facility.

The Qualifying Facility or Solid Waste Facility shall owe Tampa Electric and be liable for the credit balance in the Capacity Account. The annual balance in the Capacity Account shall accrue interest at an annual rate of 9.95%. Tampa Electric agrees to notify the Qualifying Facility or Solid Waste Facility monthly as to the current Capacity Account Balance. Prior to receipt of Early, Levelized, or Early Levelized Capacity Payments the Qualifying Facility shall secure its obligation to repay any credit balance in the Capacity Account in the event the Qualifying Facility defaults under the terms of its "Standard Offer Contract" with the Company. Such promise shall be secured by means mutually acceptable to the Parties. Florida Statute 377.709 (4) requires a Solid Waste Facility, owned or operated by, or on behalf of, a local government, which meet the criteria, described in FPSC Rule 25-17.091, F.A.C., to refund early capacity payments, should a Solid Waste Facility be abandoned, closed down, or rendered illegal. The total Capacity Account shall immediately become due and payable in the event of default by the Qualifying Facility or Solid Waste Facility.

C. **Additional Criteria**

1) The Qualifying Facility or Solid Waste Facility shall provide monthly generation estimates by October 1 for the next calendar year; and

2) The Qualifying Facility or Solid Waste Facility shall promptly update its yearly generation schedule when any changes are determined necessary; and

3) The Qualifying Facility or Solid Waste Facility shall agree to reduce generation or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and

4) The Qualifying Facility or Solid Waste Facility shall coordinate scheduled outages with the Company; and

5) The Qualifying Facility or Solid Waste Facility shall comply with the reasonable requests of the Company regarding daily or hourly communications.

DELIVERY VOLTAGE ADJUSTMENT

Energy payments to Qualifying Facilities or Solid Waste Facilities within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0737
GSD, GSLD, SBF	1.0555
IS-1, IS-3, SBI-1, SBI-3	1.0250

METERING REQUIREMENTS
Qualifying Facilities or Solid Waste Facilities within the territory served by the Company shall be required to purchase from the Company the metering necessary to measure their energy production. Hourly recording meters shall be required for Qualifying Facilities or Solid Waste Facilities with an installed capacity of 100 kilowatts or more. For Qualifying Facilities or Solid Waste Facilities with an installed capacity of less than 100 kilowatts, at the option of the Qualifying Facility or Solid Waste Facility, either hourly recording meters, dual kilowatt-hour register time-of-day meters, or standard kilowatt hour meters shall be installed. Unless special circumstances warrant, meter shall be read at monthly intervals on the approximate corresponding day of each meter reading period. Energy purchases from Qualifying Facilities or Solid Waste Facilities outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering Firm Capacity and Energy to the Company.

For the purpose of this schedule, the on-peak hours occur Monday through Friday except holidays, April 1 - October 31 from 12 noon to 9:00 p.m., and November 1 - March 31 from 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m. All hours not mentioned above and all hours of the holidays of the New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

BILLING OPTIONS
The Qualifying Facility or Solid Waste Facility upon entering into a contract for the sale of Firm Capacity and Energy or prior to delivery of As-available Energy to Tampa Electric Company shall elect to make either simultaneous purchases from the interconnecting utility and sales to Tampa Electric Company or net sales to Tampa Electric Company. The billing option elected may only be changed:

1. when the Qualifying Facility or Solid Waste Facility selling As-available Energy enter into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or

2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the Qualifying Facility, Solid Waste Facility, or Tampa Electric Company; or

3. when the Qualifying Facility or Solid Waste Facility is selling As-available Energy and has not changed billing methods within the last twelve months; and

4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the Qualifying Facility or Solid Waste Facility and Tampa Electric Company.

If the Qualifying Facility or Solid Waste Facility elects to change billing methods in accordance with FPSC Rule 25-17.082, such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice;

2. upon the installation by Tampa Electric Company of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Qualifying Facility or Solid Waste Facility for such metering equipment and its installation; and

3. upon completion and approval by Tampa Electric Company of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the Qualifying Facility or Solid Waste Facility for such alterations.

Should a Qualifying Facility or Solid Waste Facility elect to make simultaneous purchases and sales, purchases of electric service by the Qualifying Facility or Solid Waste Facility from the interconnecting utility shall be billed at the retail rate schedule under which the Qualifying Facility or Solid Waste Facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the Qualifying Facility or Solid Waste Facility to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

Should a Qualifying Facility or Solid Waste Facility elect a net billing arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832, purchases from the interconnecting utility shall be billed pursuant to the utilities applicable standby service or supplemental service rate schedules.

Under the net sales billing option, the Qualifying Facility or Solid Waste Facility may commit Firm Capacity to the Tampa Electric system. Committed capacity is described in the standard offer contract. For the net sales billing option, the committed capacity is additional to internal use, and the rates for purchase, and the performance criteria apply only to the power delivered to Tampa Electric. Although a billing option may be changed in accordance with FPSC Rule 25-17.082 the committed capacity may only change through mutual negotiations satisfactory to the Qualifying Facility or Solid Waste Facility and Tampa Electric Company.

A statement covering the charges and payments due the Qualifying Facility or Solid Waste Facility is rendered monthly and payment normally is made by the twentieth business day following the end of the billing period.

CHARGES TO QUALIFYING FACILITY OR SOLID WASTE FACILITY

A. Customer Charges

Monthly customer charges for meter reading, billing and other applicable administrative costs by Rate Schedule are:

RS	$ 7.00	RST	$ 10.00
GS	7.00	GST	10.00
GSD	35.00	GSDT	42.00
GSLD	170.00	GSLDT	170.00
SBF	195.00	SBFT	195.00
IS-1	670.00	IST-1	670.00
IS-3	710.00	IST-3	710.00
SBI-1	695.00	SBIT-1	695.00
SBI-3	735.00	SBIT-3	735.00

B. Interconnection Charge for Non-Variable Utility Expenses

The Qualifying Facility or Solid Waste Facility shall bear the cost required for interconnection including the metering. The Qualifying Facility or Solid Waste Facility shall have the option of payment in full for interconnection or make equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

C. Interconnection Charge for Variable Utility Expenses

The Qualifying Facility or Solid Waste Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include **a)** the Company's inspections of the interconnection and **b)** maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility or Solid Waste Facility if no sales to the Company were involved.

D. Taxes and Assessments

The Qualifying Facility or Solid Waste Facility shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of Firm Capacity and Energy produced by the Qualifying Facility or Solid Waste Facility.

TERMS OF SERVICE

1) It shall be the Qualifying Facility's or Solid Waste Facility's responsibility to inform the Company of any change in its electric generation capability.

2) Any electric service delivered by the Company to the Qualifying Facility or Solid Waste Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

   A) In the first year of operation, the security deposit should be based upon the singular month in which the Qualifying Facility's or Solid Waste Facility's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the Qualifying Facility or Solid Waste Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit should be required upon interconnection.

B) For each year thereafter, a review of the actual sales and purchases between the Qualifying Facility or Solid Waste Facility and the utility should be conducted to determine the actual month of maximum difference. The security deposit should be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Qualifying Facility or Solid Waste Facility exceed the actual sales to the utility in that month.

4) The Company shall specify the point of interconnection and voltage level.

5) The Company will, under the provisions of this Schedule, require an agreement with the Qualifying Facility or Solid Waste Facility upon the Company's filed Standard Offer Contract and Interconnection Agreement. The Qualifying Facility or Solid Waste Facility shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6) Service under this rate schedule is subject to the rules and regulations of the Company and the Florida Public Service Commission.

SPECIAL PROVISIONS

1) Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the Florida Public Service Commission.

2) In accordance with the provision in Rule 25-17.0883, the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charges, term, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers.

   A determination of whether or not transmission service for self-service wheeling is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3) In accordance with Rule 25-17.089, upon request by a Qualifying Facility or Solid Waste Facility, Tampa Electric Company shall provide transmission service to wheel As-Available Energy or Firm Capacity and Energy produced by a Qualifying Facility or Solid Waste Facility from the Qualifying Facility or Solid Waste Facility to another electric utility.

4) Where existing Company transmission capacity exists, the Company will impose a charge for wheeling Qualifying Facility or Solid Waste Facility energy, measured at the point of delivery to the Company. The rates, terms, and conditions for such transmission service shall be those approved by the Federal Energy Regulatory Commission.

5) The Company's actual rates for providing transmission service will be determined on an individually negotiated case-by-case basis in order to allow for variations in providing such service under different circumstances. The Company will provide, upon request, estimates of the availability and cost and terms and conditions of providing the specified desired transmission wheeling service.

6) The Qualifying Facility or Solid Waste Facility shall be responsible for all costs associated with such wheeling and the Company will deduct such costs from payments to the Qualifying Facility or Solid Waste Facility including:

   a) Wheeling charges
   b) Line losses incurred by the Company
   c) Inadvertent energy flows resulting from such wheeling.

7) Energy delivered to the Company shall be adjusted before delivery to another utility as follows:

Qualifying Facility or Solid Waste Facility Rate Schedule	Adjustment Factor
RS, GS	0.9313
GSD, GSLD, SBF	0.9474
IS-1, IS-3, SBI-1, SBI-3	0.9756

8) The Company may deny, curtail, or discontinue transmission service to a Qualifying Facility or Solid Waste Facility on a non-discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the Company's general body of retail and wholesale customers.

Schedule of COG-2

Table of Appendices

STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR SOLID WASTE FACILITIES (QUALIFYING FACILITIES)
SCHEDULE COG-2
APPENDIX A

APPLICABILITY

Appendix A provides a detailed description of the methodology used by the Company to calculate the monthly value of deferring the Designated Avoided Unit referred to in Schedule COG-2. When used in conjunction with the current FPSC approved cost parameters associated with the Designated Avoided Unit contained in Appendix B, a Qualifying Facility or Solid Waste Facility may determine the applicable value of deferral capacity payment rate associated with the timing and operation of its particular facility should the Qualifying Facility or Solid Waste Facility enter into a "Standard Offer Contract" with the utility.

Also contained in Appendix A is a discussion of the types and forms of surety bond requirements or equivalent assurance of repayment of early capacity payments acceptable to the Company in the event of contractual default by a Qualifying Facility or Solid Waste Facility.

CALCULATION OF VALUE OF DEFERRAL

FPSC Rule 25-17.0832(5) specifies that avoided capacity costs, in dollars per kilowatt per month, associated with firm capacity sold to a utility by a Qualifying Facility or Solid Waste Facility pursuant to the utility's standard offer shall be defined as the value of a year-by-year deferral of the Designated Avoided Unit and shall be calculated as follows:

$$VAC_m = \frac{1}{12} \left[KI_n \left[\frac{1 - \frac{(1 + i_p)}{(1 + r)}}{1 - \frac{(1 + i_p)^L}{(1 + r)^L}} \right] + O_n \right]$$

Where, for a one year deferral:

VAC_m = utility's monthly value of avoided capacity, in dollars per kilowatt per month, for each month of year n;

K = present value of carrying charge for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

I_n = total direct and indirect costs, in dollars per kilowatt including AFUDC but excluding CWIP, of the Designated Avoided Unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year, of the Designated Avoided Unit;

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

r = annual discount rate, defined as the utility's incremental after tax cost of capital;

L = expected life of the Designated Avoided Unit; and

n = year for which the Designated Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm energy and capacity.

Normally, payment for Firm Capacity shall not commence until the in-service date of the Designated Avoided Unit. At the option of the Qualifying Facility or Solid Waste Facility, however, the utility may begin making early capacity payments consisting of the capital cost component of the value of a year-by-year deferral of the Designated Avoided Unit starting as early as two years prior to the anticipated in-service date of the Designated Avoided Unit. When such early capacity payments are elected, the avoided capital cost component of capacity payments shall be paid monthly commencing no earlier than the Commercial In-Service date of the Qualifying Facility or Solid Waste Facility, and shall be calculated as follows:

$$A_m = A_c \frac{(1 + i_p)^{(m-1)}}{12} + A_o \frac{(1 + i_o)^{(m-1)}}{12} \qquad \text{for } m = 1 \text{ to } t$$

Where:

A_m = monthly avoided capital cost component of capacity payments to be made to the Qualifying Facility or Solid Waste Facility starting as early as two years prior to the anticipated in-service date of the Designated Avoided Unit, in dollars per kilowatt per month;

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit;

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit;

m = year for which early capacity payments to a Qualifying Facility or Solid Waste Facility are made, starting in year one and ending in the year t;

$$A_c = F \left[\frac{1 - \dfrac{(1 + i_p)}{(1 + r)}}{1 - \dfrac{(1 + i_p)^t}{(1 + r)^t}} \right]$$

Where:

F = the cumulative present value in the year that contractual payments will begin, of the avoided capital cost component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s);

r = annual discount rate, defined as the utility's incremental after tax cost of capital; and

t = the term, in years, of the contract for the purchase of firm capacity

$$A_o = G \left[\frac{1 - \dfrac{(1 + i_o)}{(1 + r)}}{1 - \dfrac{(1 + i_o)^t}{(1 + r)^t}} \right]$$

Where: G = The cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Avoided Unit.

Monthly Levelized and Early Levelized Capacity Payments shall be calculated as follows:

$$P_L = \frac{F}{12} \quad X \quad \frac{r}{1-(1 + r)^{-t}} \quad + \quad 0$$

Where:

P_L = the monthly Levelized Capacity Payment, starting on or prior to the in-service date of the designated Avoided Unit;

F = the cumulative present value, in the year that the contractual payments will begin, of the avoided capital cost component of the capacity payments which would have been made had the capacity payments not been levelized;

r = the annual discount rate, defined as the Company's incremental after tax cost of capital; and

t = the term, in years, of the contract for the purchase of firm capacity.

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with FPSC Rule 25-17.0832, paragraph 5(a) for Levelized Capacity Payments or with paragraph 5(b) for Early Levelized Capacity Payments.

Currently approved parameters applicable to the formulas above are found in Appendix B.

CALCULATION OF 12-MONTH ROLLING AVERAGE CAPACITY FACTOR

Pursuant to FPSC Rule 25-17.0832, F.A.C., and Docket No. 891049-EU, a Qualifying Facility or Solid Waste Facility must meet the Minimum Performance Standards (MPS) of the Designated Avoided Unit as described in Appendix C in order to receive capacity payments.

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SURETY BOND REQUIREMENTS

Tampa Electric will require provisions to protect its ratepayers, in the event the Qualifying Facility fails to deliver Firm Capacity and Energy in the amount and times specified, which may be in the form of an up-front payment, surety bond or equivalent assurance of payment. Such payment or surety shall be refunded upon completion of the facility and demonstration that the facility can deliver the amount of Firm Capacity and Energy specified.

FPSC Rule 25-17.0832(3)(c), F.A.C., also requires that when early capacity payments are elected, the Qualifying Facility must provide a surety bond or equivalent assurance of repayment of Early Capacity Payments in the event the Qualifying Facility is unable to meet the terms and conditions of its contract. Depending on the nature of the Qualifying Facility's operation, financial health and solvency, and its ability to meet the terms and conditions of the Company's "Standard Offer Contract" one of the following may constitute an equivalent assurance of repayment:

1) Surety bond;

2) Escrow;

3) Irrevocable letter of credit;

4) Unsecured promise by a privately owned Qualifying Facility to repay early capacity payments in the event of default in conjunction with a legally binding commitment from the owner(s) of the Qualifying Facility, parent company, and/or subsidiary companies allowing the utility to levy a surcharge on the electric bills of the owner(s), parent company, and/or subsidiary companies located in Florida to assure that early capacity payments are repaid; or

5) Other guarantee acceptable to the Company.

The Company will cooperate with each Qualifying Facility applying for early capacity payments to determine the exact form of an "equivalent assurance of repayment" to be required based on the particular aspects of the Qualifying Facility. The Company will endeavor to accommodate an equivalent assurance of repayment which is in the best interests of both the Qualifying Facility and the Company's ratepayers.

Florida Statute 377.709(4), requires Solid Waste Facilities, owned or operated by or on behalf of a local government, which meet the criteria as described in FPSC Rule 25-17.091 F.A.C., to refund early capacity payments should a Solid Waste Facility be abandoned, closed down or rendered illegal. However, at its option, a Solid Waste Facility may provide such related guarantee.

TAMPA ELECTRIC COMPANY'S DESIGNATED AVOIDED UNIT PARAMETERS FOR AVOIDED CAPACITY COSTS SCHEDULE COG-2 APPENDIX B

Where, for one year deferral:

			Value
VAC_m	=	utility's monthly value of avoided capacity, in dollars per kilowatt per month, for each month of year n;	4.83
K	=	present value of carrying charge for one dollar of investment over L years with carrying charges computed using average annual ratebase and assumed to be paid in the middle of each year and present value to the middle of the first year;	1.6446
I_n	=	total direct and indirect costs, in dollars per kilowatt including AFUDC but excluding CWIP, of the Designated Avoided Unit with an in-service date of year n, including all identifiable and quantifiable costs relative to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit been constructed;	592.4
O_n	=	total fixed operating and maintenance expense for year n, in mid-year dollars per kilowatt per year, of the Designated Avoided Unit;	1.16
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit;	5.1%
i_o	=	annual escalation rate associated with the operation and maintenance expenses of the Designated Avoided Unit;	4.8%
r	=	annual discount rate, defined as the utility's incremental after tax cost of capital;	9.95%
L	=	expected life of the Designated Avoided Unit; and	30
n	=	year for which the Designated Avoided Unit is deferred starting with its originally anticipated in-service date and ending with the termination of the contract for the purchase of firm energy and capacity;	1996

**TAMPA ELECTRIC COMPANY'S DESI .ATED AVOIDED UNIT
PARAMETERS FOR AVOIDED CAPACITY COSTS
SCHEDULE COG-2
APPENDIX B**

			Value
A_m	=	monthly avoided capital cost component of capacity payments to be made to the Qualifying Facility or Solid Waste Facility starting as early as two years prior to the anticipated in-service date of Designated Avoided Unit, in dollars per kilowatt per month;	3.47
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit;	5.1%
n	=	year for which early capacity payments to a Qualifying Facility or Solid Waste Facility are made;	1994
F	=	assuming the two year early payment option (1994), the cumulative present value of the avoided capital cost component of capacity payments which would have been paid had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit. Other option years will change the value of F (1990 $);	269.98
r	=	annual discount rate, defined as the utility's incremental after tax cost of capital; and	9.95%
t	=	the term, in years, of the contract for the purchase of firm capacity commencing prior to the in-service date of the Designated Avoided Unit, and commencing with the year in which the Qualifying Facility or Solid Waste Facility elects to receive early capacity payments.	12

Parameters for Avoided Variable Operation and Maintenance Costs

Beginning on January 1, 1996, to the extent that the Designated Avoided Unit would have been operated had it been installed by Tampa Electric:

O_v	=	total variable operating and maintenance expense, in $/MWH, of the Designated Avoided Unit:	10.63
i_v	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit:	4.8%

TAMPA ELECTRIC COMPANY'S DESIGNATED AVOIDED UNIT
MINIMUM PERFORMANCE STANDARDS
SCHEDULE COG-2
APPENDIX C

Tampa Electric Company's (TEC) Standard Offer Contract will be based on a 1996, 75 megawatt (MW), Combustion Turbine. Due to our requirements for peaking power in the mid to late 1990's, and the two (2) year minimum lead time required for its construction, the 1996 combustion turbine is TEC's designated avoided unit offered to QFs (small qualifying facilities below 75 MWs and solid waste facilities) under a Standard Offer Contract effective January 1, 1994 through December 31, 2005.

All Firm Capacity and Energy committed by QFs and solid waste facilities shall meet the following Minimum Performance Standards (MPS), which shall approximate the anticipated peak and off-peak availability and net operating factor of the 1996, 75 MW, combustion turbine designated avoided unit, over the term of the contract. The QF may elect either a **Non-Dispatchable** or a **Dispatchable** option depending on his particular operation:

Option 1 (Non-Dispatchable):
For QF processes that are non-dispatchable operations, and typically operate on a continuous (base loaded) basis, the QF may elect a non-dispatch option. Under this option, the QF's performance for the purpose of receiving capacity payments will be measured by Non-Dispatch-Option Minimum Performance Standards:

1. Availability - The QF shall provide one megawatt or greater of export to TEC at a monthly minimum of 70% of all hours in the load zones specified for this option (excluding 2 weeks for annual planned maintenance to be scheduled and coordinated in advance with TEC). The QF must meet the minimum performance standards for availability on a 12-month rolling weighted average basis in order to receive a monthly capacity payment. TEC shall record power flow from the QF into TEC's electric grid and this will be a measurement of the QF's generator availability. In addition;

2. Net Operating Factors (NOF) - The QF shall provide committed capacity into the TEC electric grid in order to meet or exceed the following monthly composite net operating factors on a 12-month rolling weighted average basis. The net composite operating factor is defined as the sum of all megawatthours provided to TEC during a specified number of hours (service hours) divided by the product of the "contracted committed capacity" megawatts and the service hours for the month. The QF must meet or exceed the minimum performance standards for the monthly composite net operating factors on a 12-month rolling average basis in order to receive monthly capacity payments.

Composite Net Operating Factors	
Jan	72.2%
Feb	83.7%
Mar	96.2%
Apr	87.7%
May	85.8%
Jun	88.8%
Jul	87.7%
Aug	89.4%
Sep	89.8%
Oct	85.9%
Nov	84.3%
Dec	88.2%

2.1 Service Hours - are defined as the number of hours during a month that TEC's system load is expected to peak and/or during which unexpected critical unit failure(s) may occur. In order to receive capacity payments, a QF generator will be required to provide capacity which meets or exceeds the appropriate monthly composite NOF percentage during the service hours in order to approximate the peaking and back-up service required from the 75 megawatt combustion turbine the Standard Offer is designed to avoid. The service hours for each month are as follows:

	Service Hours - Monthly		
	Weekday	Weekend	Sum
Jan	4	1	5
Feb	3	1	4
Mar	5	3	8
Apr	19	14	33
May	17	13	30
Jun	50	34	84
Jul	38	24	62
Aug	51	38	89
Sep	55	37	92
Oct	46	24	70
Nov	49	29	78
Dec	5	6	11

2.2 Threshold Hours - are defined to be a subset of all hours in the load zones for the month. Threshold hours are calculated by dividing service hours by the availability percentage (70%) rounded up to the nearest whole hour. Threshold hours represent the total number of hours each month from which the QF's monthly performance will be evaluated. In order to determine whether or not the QF has met the minimum NOF criteria, the QF's maximum hourly performance, based on a number of hours equivalent to the service hours specified for each month, will be selected from the following threshold hours:

	Threshold Hours - Monthly Weekday	Weekend	Sum
Jan	6	2	8
Feb	5	2	7
Mar	7	4	11
Apr	28	20	48
May	25	19	44
Jun	72	49	121
Jul	55	35	90
Aug	73	56	129
Sep	79	54	133
Oct	67	35	102
Nov	71	42	113
Dec	8	9	17

2.3 Typical Peak Load Zones - In order to meet the **Non-Dispatchable** Minimum Performance Standards for availability and net operating factor, the QF should target export into the TEC electric grid during TEC's projected peak load periods as shown below. The QF shall operate his generator such that his maximum export coincides with these peak load zones. In order to assist the **Non-Dispatchable** QF in planning the operation of his process, TEC will provide, at the request of the QF, TEC's typical projected load shapes. It is likely that TEC's peak load periods will occur within the following load zones:

	Both Weekday & Weekend - Daily
Jan - Mar	6 AM - 1 PM & 4 PM - 11 PM
Apr - Jun	2 PM - 11 PM
Jul - Oct	11 AM - 11 PM
Nov & Dec	6 AM - 1 PM & 4 PM - 11 PM

3. Minimum Performance Measurements - on a 12-month rolling average basis, the QF must meet both the availability and net operating factor criteria to receive a capacity payment for the month in question.

Example:

A QF has signed a Standard Offer Contract with TEC for 25 MWs; the QF has elected a non-dispatch option and an early capacity payment; the QF came on-line January 1994. A determination is being made in this example as to whether the QF is entitled to capacity payment following the month of March 1994.

A) Availability - The QF has been recorded as supplying export power into the TEC electric grid for 1000 hours through March 1994, at 1 MW or greater. This is greater than 70% of all hours in the load zones for, January-March 1994 the Minimum Performance Standard based upon (1000 hours/1260 hours X 100% = 79.4%). Therefore, the availability requirement has been met.

B) Net Operating Factor - The QF has provided committed capacity in March 1994 during the load zones for March (6 AM - 1 PM & 4 PM - 11 PM).

Step 1. Since there are 11 (7 weekday & 4 weekend) threshold hours defined for March, 11 of TEC's highest peaks will be identified within the load zones defined (7 weekday & 4 weekend). The QF export contribution will be identified coincident with each of these peaks. For instance,

Clock Hour	Threshold Hour	TEC Peak	QF Export
Weekday			
1 PM	1	2700	23
7 AM	2	2550	15
8 AM	3	2600	20
5 PM	4	2330	25
1 PM	5	2420	24
8 AM	6	2200	25
9 AM	7	2310	25
Weekend			
10 AM	8	1750	0
9 PM	9	1612	20
6 PM	10	1580	24
7 AM	11	1630	25

Step 2. Since there are 8 (5 weekday & 3 weekend) service hours defined for March, 8 of the QF's highest export megawatts (5 weekday & 3 weekend) will be selected to determine his net operating factor . For instance,

QF's Composite Net Operating Factor For March
= (25 + 25 + 25 + 24 + 23) + (25 + 24 + 20)/
(25 X 8) = 95.5%

Step 3. A rolling weighted average (not to exceed 12 months) is calculated based on the number of service hours in each month and the QF's performance measured against the composite NOF for the prior months of January and February. For instance,

Rolling Weighted Average (January thru March)
NOF = [(96.8 X 5) + (97.2 X 4) + (95.5 X 8)]/
(5 + 4 + 8) = 96.3%

Since the rolling weighted average of 96.3 percent exceeds the defined NOF required for March, 96.2 percent, the NOF criteria for March has been satisfied.

C) Capacity Payment - If both the availability and net operating factor criteria have been met, the QF is entitled to the early capacity payment for March.

D) Energy Payment - The QF is entitled to energy payment regardless of the MPS criteria requirements for capacity payment. Prior to the in-service date of the designated avoided unit, the basis for the QF energy payment will be the "system avoid energy cost." Following the in-service date for this designated avoided unit, the QF's energy payment will be based on either the "system avoided energy cost" or on the "designated avoided unit cost," if it has been determined the avoided unit would have been dispatched.

4. Maintenance Effects - The QF shall coordinate scheduled outages with TEC and promptly provide updates to these scheduled outages. Preferably scheduled outages should take place in low-load months, typically in the months of May and November each year. For purposes of these MPSs, the QF will be measured for availability and net operating factor during those typical peak load zones excluding scheduled outage hours not to exceed two weeks (14 days) during the calendar year for scheduled maintenance.

Option 2 (Dispatchable):
For QF processes that are dispatchable and typically operate on a cyclical basis, the QF may elect the dispatch option and will be measured for capacity payment by the Dispatch-Option Minimum Performance Standards:

1. Firm Commitment - The QF shall provide capacity to TEC on a firm commitment, first-call, on-call, as-needed, basis. For this commitment, the QF is entitled to a firm capacity payment, whether TEC dispatch personnel call for the capacity or not, but must have passed the availability measurement for the month. In the event the TEC dispatcher calls the QF to schedule QF export into the TEC electric grid, the "contracted" capacity must be provided at a minimum net operating factor criteria.
2. Availability - The QF shall provide 1 megawatt or greater of export to TEC at a monthly minimum of 53.42% of all hours in the load zones specified (excluding 2 weeks annually for planned maintenance to be scheduled and coordinated in advance with TEC). The QF must meet the Minimum Performance Standards for availability on a 12-month rolling weighted average basis in order to receive a monthly capacity payment. TEC shall record power flow from the QF into TEC's electric grid, and this will be a measure of the QF's generator availability. In addition,

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3. Net Operating Factors (NOF) - The QF shall provide committed capacity into the TEC electric gr on an "on-call" basis. TEC dispatch personnel shall call the QF operator at a minimum of 15 minutes prior to the peak export required from the QF. The TEC dispatcher will indicate the starting time and ending time (Threshold Hours) that committed capacity is required from the QF. The QF's monthly composite net operating factor will be calculated and included in the QF's 12-month rolling weighted average net operating factor. The 12-month rolling weighted average will then be compared to the NOF listed for the appropriate month as follows:

Composite Net Operating Factors	
Jan	72.2%
Feb	83.7%
Mar	96.2%
Apr	87.7%
May	85.8%
Jun	88.8%
Jul	87.7%
Aug	89.4%
Sep	89.8%
Oct	85.9%
Nov	84.3%
Dec	88.2%

3.1 Service Hours - are defined as the number of hours during a month that TEC's system load is expected to peak and/or during which unexpected critical unit failure(s) may occur. In order to receive capacity payments, a QF generator will be required to provide capacity which meets or exceeds the appropriate monthly composite NOF percentage during the service hours in order to approximate the peaking and back-up service required from the 75 megawatt combustion turbine the Standard Offer is designed to avoid. The service hours for each month are as follows:

	Service Hours - Monthly		
	Weekday	Weekend	Sum
Jan	4	1	5
Feb	3	1	4
Mar	5	3	8
Apr	19	14	33
May	17	13	30
Jun	50	34	84
Jul	38	24	62
Aug	51	38	89
Sep	55	37	92
Oct	46	24	70
Nov	49	29	78
Dec	5	6	11

3.2 Expected Dispatch Threshold Hours - are defined to be a portion of all hours in the load zones for the month. Threshold hours are calculated by dividing service hours by the availability percentage (53.42%) rounded up to the nearest whole hour. Threshold hours are as follows and indicate the expected number of hours the QF may be required to dispatch committed capacity (export) into the TEC electric grid:

	Threshold Hours - Monthly		
	Weekday	Weekend	Sum
Jan	8	3	11
Feb	7	3	10
Mar	10	6	16
Apr	37	26	63
May	33	24	57
Jun	95	64	159
Jul	72	46	118
Aug	96	73	169
Sep	104	70	174
Oct	87	46	133
Nov	93	55	148
Dec	11	11	22

3.3 Actual Dispatched Hours Less Than Expected Dispatch Threshold Hours - The QF may be dispatched less than the expected hours defined in the Dispatch Threshold Hours above. In the event the QF is dispatched less than the expected hours, the Service Hours for the month will be adjusted by multiplying 53.42 percent times the Actual Dispatched Hours. These adjusted Service Hours as calculated and rounded to the nearest whole hour will be used to select the QF's maximum export levels to determine the QF's NOF performance. This will be determined for both the weekday and weekend periods. The monthly NOF thus calculated will then be included in the 12-month rolling weighted average calculation. The 12-month rolling weighted average must be equal or greater than the composite NOF percent defined for the month in question in order for the QF to be entitled to a capacity payment.

3.4 Actual Dispatch Hours Greater Than Expected Dispatch Threshold Hours - The QF may be dispatched in excess of the expected hours defined in the Expected Dispatch Threshold Hours above. In the event the QF is dispatched above the expected hours, the actual dispatched hours will be used to select the QF's maximum export levels up to the "defined" Service Hours. And, the QF's NOF will be determined based on these same Service Hours. The QF will be given credit for any improvement in determining his NOF on the basis of actual dispatched hours, and will not be penalized if his NOF is not improved on this basis. In this case, NOF will be based on the expected dispatch threshold hours and will be used to calculate the QF's 12-month rolling weighted average. Whichever is used, either actual or expected hours, the 12-month rolling average must be equal or greater than the composite NOF percent defined for the month in question in order for the QF to be entitled to a capacity payment.

3.5 Load Zones - In order to meet the Dispatch Minimum Performance Standards for availability and net operating factor, the QF is expected to supply export into the TEC electric grid during TEC's expected peak load periods as shown below. When called upon to do so, the QF shall operate his generator such that his committed capacity coincides with these peak load zones. It is expected that TEC's peak load periods will likely occur within the load zones stated below. The QF should expect to be called and dispatched sometime during these hours.

	Both Weekday & Weekend - Daily
Jan - Mar	6 AM - 1 PM & 4 PM - 11 PM
Apr - Jun	2 PM - 11 PM
Jul - Oct	11 AM - 11 PM
Nov & Dec	6 AM - 1 PM & 4 PM - 11 PM

3.6 Outside Load Zones - The QF may be called upon for dispatch outside the Load Zones defined above. In the event the QF has been dispatched outside the Load Zones, the QF will be given the benefit of only improving his NOF percent for the month, and will not be penalized as a result of requests to dispatch committed capacity which fall outside the expected Load Zones.

4. Minimum Performance Measurements - on a 12-month rolling average basis, the QF must meet both the availability and net operating factor criteria to receive a capacity payment for the months he is called upon to supply his "committed" capacity. For those months he is not called upon, the QF must only meet the availability performance standard in order to receive capacity payment.

Example
Actual Dispatch Hours Less Than Expected
Threshold Hours (3.3)

A QF has signed a Standard Offer Contract with TEC for 25 MWs; the QF has elected a dispatch option and early capacity payment; the QF came on-line January 1994. The QF has been dispatched six times during weekday and four times during the weekend periods, which are less than Expected Dispatch Hours for the month in each period. A determination must be made as to whether the QF is entitled to a capacity payment following the month of March 1994.

A) Availability - The QF has been recorded as supplying export power into the TEC elect 'c grid for 700 hours at 1 MW or greater. This is greater than 53.42% of all hours in the load zones, January-March 1994 (700 hours/ 1260 Hours X 100% = 55.6%). Therefore, the availability requirement has been met.

B) Net Oper?ting Factor - The QF has provided committed capacity in March 1994 during the load zones for March (6 AM - 1 PM & 4 PM - 11 PM).

Step 1. Since the QF was actually dispatched less than the expected dispatch hours for the month, adjusted Service Hours must be calculated. The weekday Service Hours equals 53.42 percent times six actual dispatched hours, and the weekend Service Hours equals 53.42 percent times four actual dispatched hours. Therefore, "calculated" adjusted Service Hours would total seven (4 and 3 hours weekday and weekend respectively).

Step 2. Since the QF has actually been dispatched 10 times (6 weekday & 4 weekend) during the month of March, the QF's export contribution will be identified accordingly. For instance,

Clock Hour	Actual Dispatched Hour	TEC Peak	QF Export
Weekday			
1 PM	1	2700	23
7 AM	2	2600	15
8 AM	3	2550	20
5 PM	4	2420	25
1 PM	5	2330	24
8 AM	6	2200	25
Weekend			
9 PM	7	1630	20
6 PM	8	1612	24
7 AM	9	1580	25
8 PM	10	1000	25

Step 3. Since there are seven (4 weekday & 3 weekend) adjusted service hours "calculated" for March, seven of the QF's highest export megawatthours (4 weekday & 3 weekend) will be selected to determine his composite net operating factor. For instance,

QF's Composite Net Operating Factor For March
= (25 + 25 + 24 + 23) + (25 + 25 + 24) / (25 X 7) = 97.7%

Step 4. A 12-month rolling weighted average (not to exceed 12 months) is calculated based on the number of service hours in each month, and the QF's performance measured against the composite NOF for the prior months of January and February. For instance,

Rolling Weighted Average (January thru March)
NOF = [(96.8 X 5) + (97.2 X 4) + (97.7 X 7)]
/ (5 + 4 + 7) = 97.3%

Since the rolling weighted average of 97.3 percent exceeds the defined NOF required for March, 96.2 percent, the NOF criteria for March has been satisfied.

Example
Actual Dispatch Hours Greater Than Expected Threshold Hours (3.4)

A QF has signed a Standard Offer Contract with TEC for 25 MWs; the QF has elected a dispatch option and early capacity payment; the QF came on-line January 1994. The QF has been dispatched fifteen times during weekday, and eight times during the weekend subperiods, which is greater than Expected Dispatch Hours for the month in each period. Determination is being made as to whether the QF is entitled to a capacity payment following the month of March 1994.

A) Availability - The QF has been recorded as supplying export power into the TEC electric grid for 700 hours at 1 MW or greater. This is greater than 53.42 percent of all hours in the load zones, January-March 1994 (700 hours/1260 hours X 100% = 55.6%). Therefore, the availability requirement has been met.

B) Net Operating Factor (NOF) - The QF has provided committed capacity in March 1994 during the load zones for March (6 AM - 1 PM & 4 PM - 11 PM).

Step 1. Since actual dispatch hours exceed expected dispatch threshold hours, the Service Hours are already defined for this example and calculation is not required.

Step 2. Since the QF has been dispatched 23 times (15 weekday & 8 weekend) during the month of March, the QF's export contribution will be identified accordingly. For instance,

Clock Hour	Actual Dispatched Hour	TEC Peak	QF Export
Weekday			
1 PM	1	2700	23
7 AM	2	2600	15
8 AM	3	2550	20
5 PM	4	2420	25
1 PM	5	2330	24
8 AM	6	2310	25
9 AM	7	2200	25
7 AM	8	2200	24
6 AM	9	1950	24
10 AM	10	1850	0
1 PM	11	1830	25
8 AM	12	1800	23
9 PM	13	1790	24
8 AM	14	1780	25
7 AM	15	1710	26
Weekend			
9 PM	16	1630	20
6 PM	17	1612	24
7 AM	18	1580	25
8 PM	19	1300	25
6 AM	20	1250	25
11 PM	21	1000	20
6 PM	22	990	25
7 AM	23	980	25

Step 3. Since there are eight (5 weekday & 3 weekend) service hours defined for March, eight (8) of the QF's highest export megawatts (5 weekday & 3 weekend) will be selected to determine his net operating factor. For instance,

QF's Composite Net Operating Factor For March
= (26 + 25 + 25 + 25 + 25) + (25 + 25 + 25) /
(25 X 8) = 100.5% (cannot exceed 100.0% see note)

Note: For purposes of calculating Qf's 12-month rolling weighted average for NOF, the QF's monthly NOF percent may not exceed 100 percent of the monthly composite NOF percent.

Step 4. A 12-month rolling weighted average (not to exceed 12 months) is calculated based on the same calculations for NOF for the prior months January and February. For instance,

Rolling Weighted Average January thru March
NOF = [(96.8 X 5) + (97.[illegible] X 4) + (100.0 X 8)]
/ (5 + 4 + 8) = 98.4%

Since the rolling weighted average of 98.4 percent exceeds the defined NOF required for March, 96.2 percent, the NOF criteria for March has been satisfied.

C) Capacity Payment - In either of the two examples, both the availability and net operating factor criteria have been met, consequently, the QF is entitled to the early capacity payment for March.

D) Energy Payment - The QF is entitled to energy payment regardless of the MPS criteria requirements for capacity payment. The basis for the QF energy payment, prior to the in-service date of the avoided unit, will be the "system avoid energy cost." In the event the QF is dispatched following the in-service date for this avoided unit, the "designated avoided unit's energy cost" will be the basis for energy payment for all hours the QF was dispatched.

5. <u>Maintenance Effects</u> - The QF shall coordinate scheduled outages with TEC and promptly provide updates to these scheduled outages. Preferably scheduled outages should take place in low-load months, typically in the months of May and November each year. For purposes of these MPSs, the QF will be measured for availability and net operating factor during those typical peak load zones excluding scheduled outage hours not to exceed two weeks (14 days) during the calendar year for scheduled maintenance.

GLOSSARY OF MAJOR TERMS

Availability
State in which a unit is providing at least minimal service into the contracted utility's grid during designated load zone periods.

Scheduled Outage
The removal of a unit from service to perform work on specific components that is planned well in advance and has a predetermined duration; e.g., annual overhaul, inspections, testing.

Net Operating Factor
The actual number of electrical megawatthours generated by a unit during the service hour period being considered and measured as a fractional percentage of the maximum contractual potential for the same service hour period.

Service Hours
Total number of hours a unit was electrically connected to the electrical grid required to meet a designated peak system load or to supply back-up power for other forced unit failure(s).

Threshold Hours
Total expected hours a unit was electrically connected to the electrical grid required to meet a potential designated peak system load or to supply potential back-up power for other forced unit failure(s).

Forced Outage
An unplanned component failure (immediate, delayed, postponed, start-up failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Dispatchable
The ability to be called upon to start-up, ramp-up, shut-down, or ramp-down in such a response time as to meet or follow the anticipated load direction of the contracted utility.

Firm Capacity
Committed megawatts supplied without interruption absent events beyond the control of the supplying QF.

Expected Dispatch Threshold Hours
Those hours anticipating service is required a unit will be electrically connected to the electrical grid anticipating to meet a designated peak system load or anticipating back-up supply for other forced unit failure(s) which may be inclusive of service hours.

Load Zones
Anticipated periods it is likely peak loads may occur and the period availability is measured.

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**METHODOLOGY TO BE USED
IN THE CALCULATION OF
AVOIDED ENERGY COST
SCHEDULE COG-1
APPENDIX D**

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum spinning reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

The as-available avoided energy cost, as determined by this methodology, is priced at a level not to exceed Tampa Electric's incremental fuel and identifiable variable operating and maintenance (O&M) expenses plus the cost of any off-system purchases for native load.

Parameters For Determining As-Available Avoided Energy Costs

Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of Tampa Electric's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor, and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (4. above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

Parameters For Determining Firm Energy Avoided Costs

Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. **Prior to the in-service date:**
   Payments prior to the in-service date of the Designated Avoided Unit, the energy rate in cents per kilowatt-hour (¢/KWH) shall be based on the Company's actual hourly avoided costs which are calculated by the Company in accordance with FPSC rule 25-17.0825, F.A.C.

2. **After the in-service date:**
   Payments after the in-service date of the Designated Avoided Unit, the Firm Energy rate in cents per kilowatt-hour (¢/KWH) shall be based on the Designated Avoided Unit's energy cost (fuel and variable Operation and Maintenance), to the extent that the Designated Avoided Unit would have operated had it been installed by Tampa Electric Company.

Supplemental Fuel

The term "supplemental fuel" refers to that fuel purchased in excess of Tampa Electric's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for Tampa Electric to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. Tampa Electric pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, Tampa Electric treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

Avoid Energy Cost Calculations

Example: #1 No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its' Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standar. Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent .o the combined actual hourly generation of all QFs making as-available energy sales to Tampa Electric. In the absence of metered information, Tampa Electric's best estimate of the hourly as-available generation will be used rounded to the nearest 5 MWs. Prior to the in-service date of the appropriate designated avoided unit, firm energy s les will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the Avoided Energy Rate (AER) for the hour. The AER will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Example #2 Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its' Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit #6. (Example #3)

Line Loss Credit

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental hourly avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to Tampa Electric would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M

A procedure for approximating the "identifiable" incremental variable O&M expenses is included in Tampa Electric's methodology for the determination of incremental avoided energy costs associated with as-available energy.

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute, was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information.
Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7).

EXHIBIT #1

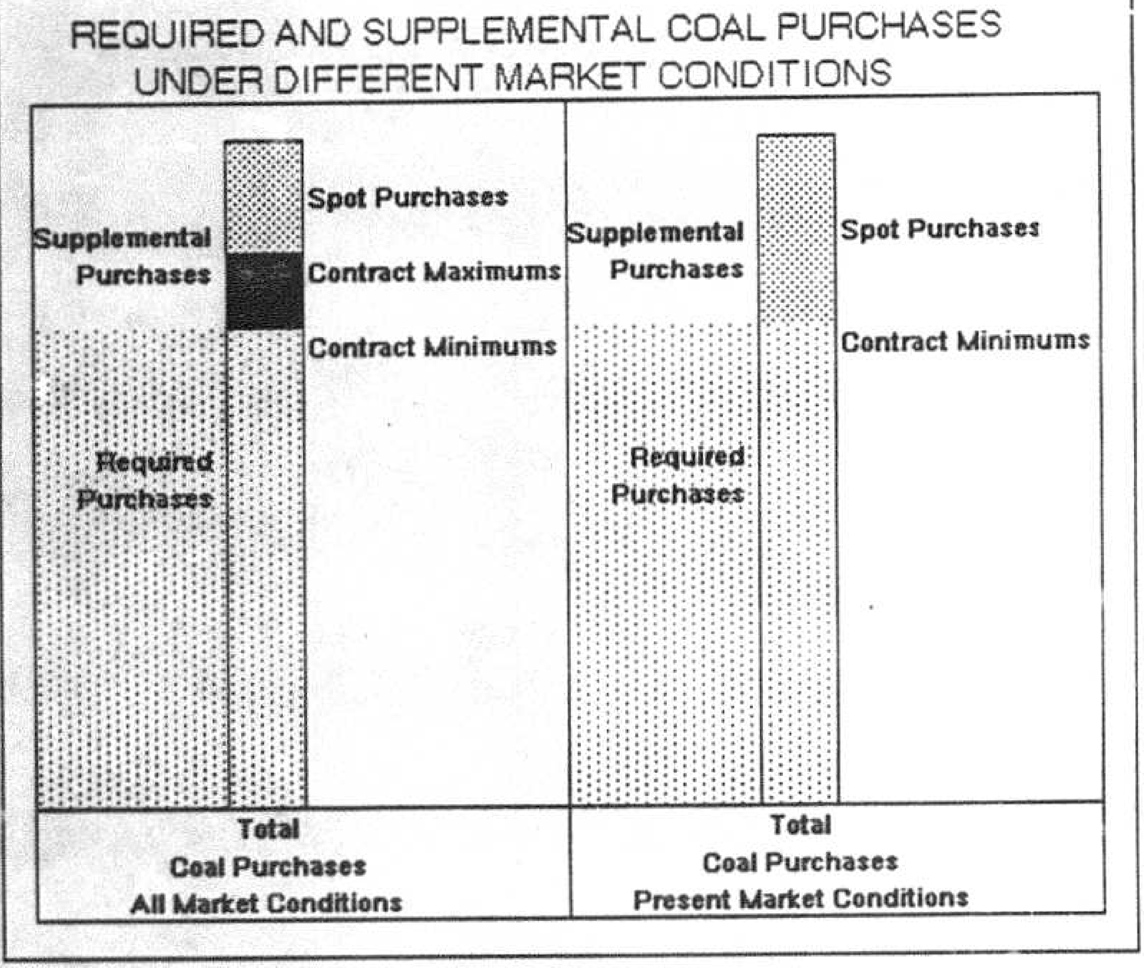
REQUIRED AND SUPPLEMENTAL COAL PURCHASES
UNDER DIFFERENT MARKET CONDITIONS
Supplemental Purchases
Spot Purchases
Contract Maximums
Contract Minimums
Required Purchases
Total Coal Purchases All Market Conditions
Supplemental Purchases
Spot Purchases
Contract Minimums
Required Purchases
Total Coal Purchases Present Market Conditions

EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENTAL FUEL COST
Gannon 1-4	A				$45.30			177.50
Gannon 5 & 6	B				$45.48			176.44
Big Bend 1 & 2	C				$29.22			123.13
	D				$31.67			
	E				$32.08			
				Average	$29.87			
Big Bend 3 [1]	F				$50.55			173.67
			Blended	Average	$42.28			
Big Bend 4	G				$41.70			181.31
	H				$37.21			
				Average	$41.11			
#2 Oil	I				$19.41/BBL			334.64

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

EXHIBIT #3

Example #1 **No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):
Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):
Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost =
($20,275/Hour - $19,500/Hour) / (50MW)

or

Avoided Energy Rate (AER) = $15.50/MWH

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EXHIBIT #4

Example #2a **Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.**

Given:
- Actual QF Energy = 50 MWs
- TEC's Maximum Available Generation = 1460 MWs
- Native Load = 1500 MWs
- Firm Sale = 10 MWs

First Calculation:
Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:
Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) =
($18,900/Hour - $18,882.50/Hour) / (1 MW)

or

Avoided Energy Rate (AER) = $17.50/MWH

NOTE: [1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

EXHIBIT #5

Example #2b **Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.**

Given:
- Actual QF Energy = 50 MWs
- TEC's Maximum Available Generation = 1530 MWs
- TEC's Actual Generation = 1500 MWs
- Native Load = 1540 MWs
- Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation ("WITHOUT" QF):

Production Cost at 1530 MWs = $20,590/Hour

Second Calculation ("With QF):

Production Cost at 1500 MWs = $20,050/Hour

Third Calculation:

Actual Hourly Avoided Energy Cost at 30 MWs =

($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:

Production Cost at 1530 MWs = $20,590/Hour

Second Calculation:

Production Cost at 1529 MWs = $20,571.50/Hour

Third Calculation:

Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) for 20 MWs =

($20,590/Hour - $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block =

$540 + $370 / 50 MW

or

Avoided Energy Rate (AER) = $18.20/MWH

NOTE:

[1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

EXHIBIT #6

Example #3 Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases[1] = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AER = $40/Hour

NOTES: [1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the Technical Assessment Guide dated May 1982, published by the Electric Power Research Institute (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:	1983 TEC Coal Generation	MW
1) Big Bend	1	367
	2	362
	3	375
	3	10 upgrade
Gannon	5	218
	6	351
	4	169 conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor $= \frac{10,493,266}{15,050,712} \times 100\%$

$= 69.72\%$

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] $= \frac{10,694,772}{10,493,266} = \$1.02/\text{MWH}$

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

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TAMPA ELECTRIC COMPANY'S STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A SMALL QUALIFYING FACILITY OR A SOLID WASTE .ACILITY

THIS AGREEMENT is made and entered into this _______ day of ______________, 19____ by and between __________________, hereinafter referred to as "QF" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida. The QF and Tampa Electric shall collectively be referred to herein as the "Parties."

WITNESSETH:

WHEREAS, QF desires to sell, and Tampa Electric desires to purchase, Firm Capacity and Energy to be generated by small QFs of less than 75MW or by solid waste facilities consistent with Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.091 of Order No. 23625 issued October 16, 1990, Docket No. 891049-EU; and

WHEREAS, QF has signed an Interconnection Agreement with the utility in whose service territory the QF's generating facility is located, attached hereto as Appendix A; and

WHEREAS, the FPSC has approved the following Standard Offer Contract for the purchase of Firm Capacity and Energy from QFs;

NOW, THEREFORE, for mutual consideration the Parties agree as follows:

1. Facilities

1.1 Designated Avoided Unit

Tampa Electric has identified a 75 MW combustion turbine with an in-service date of January 1, 1996, as it's Designated Avoided Unit. The avoided unit will be fully subscribed at 75 MWs of committed Firm Capacity and Energy.

1.2 Qualifying Facility

QF contemplates installing and operating a ________ KVA generator located at ________________________________. The generator is designed to produce a maximum of ________ megawatts (MW), or ________ kilowatts (KW) of electric power designed, operated and controlled to provide reactive power requirements from 0.85 lagging to 0.85 leading power factor, such equipment being hereinafter referred to as the "Facility."

2. Term of the Agreement

This Agreement shall begin immediately upon its execution by the parties and shall end at 12:01 a.m., ______________, 19_____.

Notwithstanding the foregoing if construction and commercial operation of the Facility are not accomplished by QF before January 1, 1996, this Agreement shall be rendered of no force and effect. The terms of this Agreement are further detailed in Rate Schedule COG-2 attached hereto as Appendix B.

3. Sale of Electricity by QF.

Tampa Electric agrees to purchase all of the electric power generated at the Facility and transmitted to Tampa Electric by QF, less the amount of electric power consumed by the QF's generator auxiliaries. The purchase and sale of electricity pursuant to this Agreement shall be construed as a (   ) Net Billing Arrangement or (   ) Simultaneous Purchase and Sale Arrangement. Once made, the selection of a billing methodology may only be changed in accordance with Rule 25-17.082 and shall be subject to the following provisions:

(a) upon at least thirty days advance written notice to Tampa Electric;

(b) upon the installation by Tampa Electric of any additional metering equipment reasonably required to effect the change in billing and upon payment by the QF for such metering equipment and its installation; and

(c) upon completion and approval by Tampa Electric of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the QF for such alternations.

The parties agree that QF's obligation to generate and sell electricity from the Facility is subject to both scheduled and unscheduled outages of the Facility and the equipment and facilities described in this Agreement. Except for any repayment of early capacity credits which may be required under Section 7 of this Agreement, neither party shall be required to compensate the other party for electrical energy which from time to time may not be generated and sold by QF or received and purchased by Tampa Electric as a result of such scheduled and unscheduled outages. The parties agree to use best efforts to minimize the duration of any scheduled or unscheduled outages which from time to time may interrupt the purchase and sale of electricity under this Agreement.

4. Payment for Electricity Produced by QF:

4.1 Energy

Tampa Electric agrees to pay the QF for energy produced by the Facility and delivered to Tampa Electric in accordance with the rates and procedures contained in Rate Schedule COG-2 attached hereto as Appendix B. Prior to January 1, 1996 QF will receive energy payments based on Tampa Electric's actual avoided energy costs. After January 1, 1996, to the extent that the Designated Avoided Unit would have been operated, the QF's energy payments will be based on Tampa Electric's Designated Avoided Unit's energy costs, otherwise QF's energy payment will be based on Tampa Electric's actual avoided energy costs as defined in COG-2, such determination to be made hourly.

4.2 Capacity

4.2.1 Anticipated Committed Capacity. QF expects to sell approximately _______ MW or _______ KW of capacity, beginning on or about ___________, 19_____.

Tampa Electric will require provisions to protect its ratepayers, in the event the QF fails to deliver Firm Capacity and Energy in the amount and times specified in this Agreement, which may be in the form of an up-front payment, surety bond or equivalent assurance of payment. Such payment or surety shall be refunded upon completion of the facility and demonstration that the facility can deliver the amount of Firm Capacity and Energy specified in this Agreement.

QF may finalize its Committed Capacity after initial Facility testing, and specify when capacity payments are to begin, by completing Paragraph 4.2.2 at a later time. However, QF must complete Paragraph 4.2.2 by January 1, 1994 in order to be entitled to any capacity payments pursuant to this Agreement.

4.2.2 **Actual Committed Capacity.** The capacity committed by QF for purposes of this Agreement is _______ MW or _______ KW. QF elects to receive, and Tampa Electric agrees to commence calculating, capacity payments in accordance with this Agreement starting with the first billing month following ___________, 19____.

4.2.3 **Firm Capacity Payment Options.** The following options are available to the QF for payment for Firm Capacity delivered by the QF:

1) Value of Deferral Capacity Payment;

2) Early Capacity Payments;

3) Levelized Capacity Payments;

4) Early Levelized Capacity Payments.

QF chooses to receive firm capacity payments from Tampa Electric under Option: _____________. Each of these options is further detailed in Tampa Electric's Rate Schedule COG-2 (Appendix B).

At the end of each billing month, beginning with the billing month specified in Paragraph 4.2.2, Tampa Electric will calculate the most recent 12 month rolling average capacity factor for such month based on QF's Committed Capacity. If the capacity factor thus calculated equals or exceeds. over the term of this Agreement, the Minimum Performance Standards (MPS), attached hereto as Appendix C in Rate Schedule COG-2, for peak and off-peak availability and capacity factor of Tampa Electric's Designated Avoided Unit, then Tampa Electric agrees to pay QF a capacity payment that is the product of QF's Committed Capacity and the applicable rate from QF's chosen capacity payment option.

The capacity payment for a given month will be added to the energy payment for such month and tendered by Tampa Electric to QF as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

5. **Electricity Production Schedule**

During the term of this Agreement, QF agrees to:

(a) Provide Tampa Electric prior to October 1 of each calendar year an estimate of the amount of electricity to be generated by the Facility and delivered to Tampa Electric for each month of the following calendar year, including the time, duration and magnitude of any planned outages or reductions in capacity;

(b) Promptly update the yearly generation schedule and maintenance schedule as and when any changes may be determined necessary;

(c) Comply with reasonable requirements of Tampa Electric regarding day-to-day or hour-by-hour communications between the parties relative to the performance of this Agreement.

6. **QF's Obligation if QF Receives Early Capacity Payments**

The QF's payment option choice pursuant to paragraphs 4.2.3 may result in early capacity payments by Tampa Electric for capacity delivered prior to

January 1, 1996. Similarly, capacity payments for capacity delivered after January 1, 1996 may also exceed the year by-year value of deferring the Designated Avoided Unit as specified in this Agreement. The parties recognize that capacity payments that exceed the year-by-year value of deferring the avoided unit, are in the nature of "early payment" for a future capacity benefit to Tampa Electric. To ensure that Tampa Electric will receive a capacity benefit for which Early, Levelized or Early Levelized Capacity Payments have been made, or alternatively, that the QF will repay the amount of early payments received to the extent the capacity benefit has not been conferred, the following provisions will apply:

Tampa Electric shall establish a Capacity Account. Amounts shall be credited to the Capacity Account each month through December 1995, in the amount of Tampa Electric's early capacity payments made to the QF pursuant to QF's chosen payment option from Rate Schedule COG-2. Beginning on January 1, 1996, the difference between the capacity payment made to the QF and the "normal" capacity payment calculated pursuant to Option #1 in COG-2 will be credited each month to the Capacity Account, so long as the payment made to the QF is greater than the monthly payment had the QF selected Option #1 on COG-2. The annual balance in the Capacity Account shall accrue interest at an annual rate of 9.95%. After January 1, 1996, at such time that the monthly capacity payment made to the QF, pursuant to the capacity payment option selected, is less than the "normal" monthly capacity payment in Option #1 of COG-2, there shall be debited from the Capacity Account an Early Payment Offset Amount to reduce the balance in the Capacity Account. Such Early Payment Offset Amount shall be equal to that amount which Tampa Electric would have paid for capacity in that month if capacity payment had been calculated pursuant to Option #1 in Rate Schedule COG-2 and the QF had elected to begin receiving payment on January 1, 1996 minus the monthly capacity payment Tampa Electric makes to QF pursuant to the capacity option chosen by QF in paragraph 4.2.3.

The QF shall owe Tampa Electric and be liable for the credit balance in the Capacity Account. Tampa Electric agrees to notify QF monthly as to the current Capacity Account balance. Prior to receipt of Early Capacity Payments, Levelized Capacity Payments or Early Levelized Capacity Payments the QF shall execute a promise to repay any credit balance in the Capacity Account in the event the QF defaults pursuant to this Agreement. Such promise shall be secured by means mutually acceptable to the Parties and in accordance with the provisions of Rate Schedule COG-2. The specific repayment assurance selected for purposes of this Agreement is: ________________________

____

The total Capacity Account shall immediately become due and payable in the event of default by the QF. The QF's obligation to pay the credit balance in the Capacity Account shall survive termination of this Agreement.

7. <u>Nonperformance Provisions</u>

QF shall not receive a capacity payment during any month in which the QF fails to meet on a 12 month rolling average basis the Minimum Performance Standards (MPS) for peak and off-peak availability and the capacity factor of

Tampa Electric's Designated Avoided Unit as defined in Appendix C in Rate Schedule COG-2. In addition, if for any month after January 1, 1996, the QF fails to achieve the MPS on a 12 month rolling average basis and the monthly capacity payment that would have been made to the QF pursuant to the capacity payment option selected is less than the normal monthly capacity payment had the QF selected option #1, then the QF shall be liable for and shall pay Tampa Electric an amount equal to the Early Payment Offset Amount for the month; provided, however, that such calculation shall assume that the QF satisfied the MPS. Any payments thus required of QF shall be separately invoiced by Tampa Electric to QF after each month for which such repayment is due and shall be paid by QF within 20 business days after receipt of such invoice by QF. Such repayment shall be debited from the Capacity Account as an Early Payment Offset Amount and will not exceed the current balance in the Capacity Account.

8. <u>Default</u>

8.1 <u>Mandatory Default.</u> The QF shall be in default under this Agreement if: (1) the QF voluntarily declares bankruptcy, or (2) the QF ceases all electric generation for 12 consecutive months.

8.2 <u>Optional Default.</u> Tampa Electric may declare the QF to be in default: (1) if at any time prior to January 1, 1996, and after capacity payments have begun, Tampa Electric has sufficient reason to believe that the QF is unable to deliver its Committed Capacity, or (2) after January 1, 1996 the QF fails to meet the MPS on a 12 month rolling average basis for 24 consecutive months, or (3) because of a QF's refusal, inability or anticipatory breach of obligation to deliver its Committed Capacity after January 1, 1996.

8.3 <u>Default Remedy.</u> Once this contract is declared to be in default, upon written notice to the QF, the then current value of the Capacity Account shall be paid to Tampa Electric by QF within 20 business days of receipt of such written notice.

9. <u>General Provisions</u>

9.1 <u>Permits.</u> QF hereby agrees to seek to obtain any and all governmental permits, certifications, or other authority QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. Tampa Electric hereby agrees to seek to obtain at QF's expense any and all governmental permits, certifications or other authority Tampa Electric is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

9.2 <u>Indemnification.</u> Tampa Electric and the QF shall each be responsible for its own facilities. Tampa Electric and the QF shall each be responsible for ensuring adequate safeguards for other Tampa Electric Customers, Tampa Electric and QF personnel and equipment, and for the protection of its own generating system. Tampa Electric and the QF shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

1) any act or omission by a party or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;

2) any defect in, failure of, or fault related to a party's generation system;

3) the negligence of a party or negligence of that party's contractors, agents servants and employees; or

4) any other event or act that is the result of, or proximately caused by a party.

For the purpose of this subsection, the term party shall mean either Tampa Electric or QF, as the case may be.

9.3 Insurance. The QF shall deliver to Tampa Electric, at least 15 days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the state of Florida naming the QF as named insured, and Tampa Electric as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

The policy providing such coverage shall provide public liability insurance, including property damage, in an amount not less than $300,000 for each occurrence; more insurance may be required as deemed necessary by Tampa Electric. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify Tampa Electric 30 days prior to the effective date of cancellation or material change in the policy.

The QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with Tampa Electric.

9.4 <u>Renegotiations Due to Regulatory Changes.</u> Anything in this Agreement to the contrary notwithstanding, should Tampa Electric at any time during the term of this Agreement fail to obtain or be denied the FPSC's authorization, or the authorization of any other regulatory body which now has, or in the future may have, jurisdiction over Tampa Electric's rates and charge, to recover from its customers all of the payments required to be made to QF under the terms of this Agreement or any subsequent amendment to this Agreement, the parties agree that, at Tampa Electric's option, they shall renegotiate this Agreement or any applicable amendment. If Tampa Electric exercises such option to renegotiate, Tampa Electric shall not thereafter be required to make such payments to the extent Tampa Electric's authorization to recover them from its customers is not obtained or is denied. Tampa Electric's exercise of its option to renegotiate shall not relieve the QF of its obligation to repay the balance in the Capacity Account. It is the intent of the parties that Tampa Electric's payment obligations under this Agreement or any amendment hereto are conditional upon Tampa Electric being fully reimbursed for such payments through the Fuel and Purchased Power Cost Recovery Clause or other authorized rates or charges. Any amounts initially recovered by Tampa Electric from its ratepayers but for which recovery is subsequently disallowed by the FPSC and charged back to Tampa Electric may be set off or credited against subsequent payments made by Tampa Electric for purchases from the QF, or alternatively, shall be repaid by the QF.

9.5 Force Majeure. If either party shall be unable, by reason of force majeure, to carry out its obligations under this Agreement, either wholly or in part, the party so failing shall give written notice and full particulars of such cause or causes to the other party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended during the continuance of such hindrance, which, however, shall be remedied with all possible dispatch; and the obligations, terms and conditions of this Agreement shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "force majeure" shall be taken to mean all acts of God, strikes, lockouts or other industrial disturbances, wars, blockades, insurrections, riots, arrests and restraints of rules and people, environmental constraints lawfully imposed by federal, state or local government bodies, explosions, fires, floods, lightning, wind, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however that no occurrence may be claimed to be a force majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the party attempting to make such claim. QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with Tampa Electric's system if the same are rendered inoperable due to actions of QF, its agents, or force majeure events affecting the Facility or the interconnection with Tampa Electric. Tampa Electric agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by Tampa Electric or its agents.

9.6 Assignment. The QF shall have the right to assign its benefits under this Agreement, but the QF shall not have the right to assign its obligations and duties without Tampa Electric's prior written consent.

9.7 Disclaimer. In executing this Agreement, Tampa Electric does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with QF or any assignee of this Agreement.

9.8 Notification. For purposes of making any and all non-emergency oral and written notices, payment or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other party written instructions to contact another individual.

For: QF

For: Tampa Electric
Assistant Director, Cogeneration
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601

9.9 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida.

9.10 Severability. If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

9.11 **Complete Agreement and Amendments.** All previous communications or agreements between the parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement.

9.12 **Incorporation of Rate Schedule.** The parties agree that this Agreement shall be subject to all of the provisions contained in Tampa Electric's published Rate Schedule COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

9.13 **Survival of Agreement.** This Agreement, as may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

IN WITNESS WHEREOF, QF and Tampa Electric have executed this Agreement the day and year first above written.

WITNESSES: **Qualifying Facility**

____________________ ____________________

____

WITNESSES: **Tampa Electric Company**

____________________ ____________________

____

DATE EFFECTIVE:

document entitled, "QF Interconnection Cost Estimates." The parties agree that the cost of the interconnection work contained in Exhibit B is an estimate of the actual cost to be incurred.

4. <u>Technical Requirements and Operations.</u>

The parties agree that QF's interconnection with, and delivery of electricity into, the Tampa Electric system must be accomplished in accordance with the provisions of Tampa Electric Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" attached hereto as Exhibit C.

In the event that changes in the engineering or operating standards or practices in the utility industry, and Tampa Electric's corresponding standards or practices or changes in regulatory requirements, affect the design or operation of Tampa Electric's electrical system, and this in turn necessitates additions to or modifications of the equipment or facilities utilized to materially effect this Agreement so as to ensure the continued safe and reliable operations provided for in this Agreement, as well as the continued compatability of the Facility with Tampa Electric's system, Q.F. agrees to bear the cost of such additions or modifications which are directly attributable to the Facility. The costs of such additions or modifications shall not include any costs which Tampa Electric would otherwise incur if it were not engaged in interconnected operations with the Facility, but instead simply provided the Facility's electrical power requirements with electricity either generated by Tampa Electric or purchased from another source.

9. Insurance

The QF shall deliver to Tampa Electric at least 15 days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the QF as named insured, and Tampa Electric as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

The policy providing such coverage shall provide public liability insurance, including property damage, in an amount less than $300,000 for each occurrence; more insurance may be required as deemed necessary by Tampa Electric. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify Tampa Electric 30 days prior to the effective date of cancellation or material change in the policy. The QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with Tampa Electric.

10. Electric Service to QF.

Tampa Electric will provide the class or classes of electric service requested by QF, to the extent that they are consistent with applicable tariffs; provided, however, that interruptible service will not be available under circumstances where interruptions would impair QF's ability to generate and deliver Firm Capacity and Energy to Tampa Electric.

11. Notification.

For purpose of making emergency or any communications relating to the operation of the Facility, under the provisions of this Agreement, the parties designate the following people for notification:

For QF:

____________________ _______________

____________________ Phone: _______________

For Tampa Electric:

Dispatcher

Palm River Phone: (813) 621-2929

IN WITNESS WHEREOF, QF and Tampa Electric have executed this Agreement the day and year first above written.

WITNESSES: **Qualifying Facility**

__________________________________ __________________________________

____

WITNESSES: **Tampa Electric Company**

__________________________________ __________________________________

____

TAMPA ELECTRIC COMPANY'S GENERAL STANDARDS FO~ SAFETY AND INTERCONNECTION OF COGENERATION AND SMALL POWER PRODUCTION FACILITIES TO THE ELECTRIC UTILITY SYSTEM

Applicable Throughout The Company's Service Area

25-17.87 Interconnection and Standards

(1) Each utility shall interconnect with any qualifying facility which:

(a) is in its service area;

(b) requests interconnection;

(c) agrees to meet system standards specified in this Rule;

(d) agrees to pay the cost of interconnection; and

(e) signs an interconnection agreement.

(2) Nothing in this rule shall be construed to preclude a utility from evaluating each request for interconnection on its own merits and modifying the general standards specified in this Rule to reflect the result of such an evaluation.

(3) Where a utility refuses to interconnect with a qualifying facility or attempts to impose unreasonable standards pursuant to subsection (2) of this rule, the qualifying facility may petition the Commission for relief. The utility shall have the

5. Failure of the qualifying facility to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the qualifying facility's electric generating equipment or the operation of such equipment.

(b) Responsibility and Liability. Tampa Electric and the QF shall each be responsible for its own facilities. Tampa Electric and the QF shall each be responsible for ensuring adequate safeguards for other Tampa Electric customers, Tampa Electric and QF personnel and equipment, and for the protection of its own generating system. Tampa Electric and the QF shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

1. Any act or omission by a party, or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;

burden of demonstrating to the Commission why interconnection with the qualifying facility should not be required or that the standards the utility seeks to impose on the qualifying facility pursuant to subsection (2) are reasonable.

(4) Upon a showing of credit worthiness, the qualifying facility shall have the option of making monthly installment payments over a period no longer than 36 months toward the full cost of interconnection. However, where the qualifying facility exercises that option, the utility shall charge interest on the amount owing. The utility shall charge such interest at the 30 day highest grade commercial paper rate. In any event, no utility may bear the cost of interconnection.

(5) Application for Interconnection. A qualifying facility shall not operate electric generating equipment in parallel with the utility's electric system without the prior written consent of the utility. Formal application for interconnection shall be made by the qualifying facility prior to the installation of any generation related equipment. This application shall be accompanied by the following:

(a) Physical layout drawings, including dimensions;

(b) All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;

(c) Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the proposed system and to be able to make a coordinated system;

(d) Power characteristics in watts and vars;

(e) Expected radio-noise, harmonic generation and telephone interference factor;

(f) Synchronizing methods; and

(g) Operating/instruction manuals.

Any subsequent change in the system must also be submitted for review and written approval prior to actual modification. The above mentioned review, recommendations and approval by the utility do not relieve the qualifying facility from complete responsibility for the adequate engineering design, construction and operation of the qualifying facility equipment and for any liability for injuries to property or persons associated with any failure to perform in a proper and safe manner for any reason.

(6) Personnel Safety. Adequate protection and safe operational procedures must be developed and followed by the joint system. These operating procedures must be approved by both the utility and the qualifying facility. The qualifying facility shall be required to furnish, install, operate and maintain in good order and repair, and be solely responsible for, without cost to the utility, all facilities required for the safe operation of the generation system in parallel with the utility's system.

The qualifying facility shall permit the utility's employees to enter upon its property at any reasonable time for the purpose of inspection and/or testing the qualifying facility's equipment, facilities, or apparatus. Such inspections shall not relieve the qualifying facility from its obligation to maintain its equipment in safe and satisfactory operating condition.

The utility's approval of isolating devices used by the qualifying facility will be required to ensure that these will comply with the utility's switching and tagging procedure for safe working clearances.

(a) Disconnect switch. A manual disconnect switch, of the visible load break type, to provide a separation point between the qualifying facility's generation system and the utility's system, shall be required. The utility will specify the location of the disconnect switch. The switch shall be mounted separate from the meter socket and shall be readily accessible to the utility and be capable of being locked in the open position with a utility padlock. The utility may reserve the right to open the switch (i.e., isolating the qualifying facility's generation system) without prior notice to the qualifying facility. To the extent practicable, however, prior notice shall be given.

Any of the following conditions shall be cause for disconnection:

1. Utility system emergencies and/or maintenance requirements;
2. Hazardous conditions existing on the qualifying facility's generating or protective equipment as determined by the utility;
3. Adverse effects of the qualifying facility's generation to the utility's other electric consumers and/or system as determined by the utility;
4. Failure of the qualifying facility to maintain any required insurance; or

2. Any defect in, failure of, or fault related to a party's generation system;

3. The negligence of a party or negligence of that party's contractors, agents, servants and employees; or

4. Any other event or act that is the result of, or proximately caused by a party.

For the purpose of this subsection, the term party shall mean either Tampa Electric or QF, as the case may be.

(c) Insurance. The QF shall deliver to Tampa Electric, at least 15 days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the Qf as named insured, and Tampa Electric as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

provided. In situations where power may flow both in and out of the qualifying facility's system, power flowing into the qualifying facility's system w' l be measured separately from power flowing out of the qualifying facility's system.

The utility wi'l provide, at no additional cost to the qualifying facility, the metering equipment necessary to measure capacity and energy deliveries to the qualifying facility. The utility will provide, at the qualifying facility's expense, the necessary additional metering equipment to measure capacity and energy deliveries by the qualifying facility to the utility.

(10) Cost Responsibility. The qualifying facility is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers, lines, services, meters, switches, and associated equipment and devices beyond that which would be required to provide normal service to the qualifying facility if the QF were a non-generating customer. These costs shall be paid by the qualifying facility to the utility for all material and labor that is required. Prior to any work being done by the utility, the utility shall supply the qualifying facility

The policy providing such coverage shall provide public liability insurance, including property damage, in an amount not less than $300,000 for each occurrence; more insurance may be required as deemed necessary by Tampa Electric. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify Tampa Electric 30 days prior to the effective date of cancellation or material change in the policy.

The QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with Tampa Electric.

(7) Protection and Operation. It will be the responsibility of the qualifying facility to provide all devices necessary to protect the qualifying facility's equipment from damage by the abnormal conditions and operations which occur on the utility system that result from interruptions and restorations of service by the utility's equipment and personnel. The qualifying facility shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault condition), open circuits, phase unbalance and reversal, over or under frequency condition, and other injurious electrical conditions that may arise on the utility's system and any reclose attempt by the utility.

with a written cost estimate of all its required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to the QF within 60 days after the QF provides the utility with its final electrical plans. The utility shall also provide project timing and feasibility information to the qualifying facility.

(11) Each utility shall submit, to the Commission, a standard agreement for the interconnection by QFs as part of their standard offer contract or contracts required by Rule 25-17.0832(3).