Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Tom Washburn
Late Filed Exhibit No. 8
Page 1 of 1

STANTON ENERGY CENTER UNIT 1

AVERAGE DAILY EMISSION RATE
From
July, 1987
Thru
September 30, 1990

SO_2: 5.78 tons per day average

NO_x: 13.26 tons per day average

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Tom Washburn
Late Filed Exhibit No. 8

STANTON ENERGY CENTER UNIT 1

AVERAGE DAILY EMISSION RATE
From
July, 1987
Thru
September 30, 1990

SO_2: 5.78 tons per day average

NO_x: 13.26 tons per day average

11

EXHIBIT NO. ________________

WITNESSES: WINDISCH

DESCRIPTION: INTERROGATORY 23
PRELIMINARY ESTIMATE COAL CARS COST

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 11
COMPANY/ WITNESS: Windisch
DATE: 6/28/91

INT 23

ORLANDO UTILITIES COMMISSION
STANTON UNIT 2 425 MW
PRELIMINARY ESTIMATE 1-JAN-89 $
REPLICATION

14-May-90

SPEC NUMBER	DESCRIPTION		OUC CODE	OUC UNIT 2	1995 ESCALATION FACTOR	1995 DOLLAR TOTAL	1996 ESCALATION FACTOR	1996 DOLLAR TOTAL	1997 ESCALATION FACTOR	1997 DOLLAR TOTAL
61.0403	Bulk Materials Handling	F&E	61002	$1,157,000	1.205	$1,394,185	1.253	$1,449,721	1.283	$1,484,431
61.0405	Dust Collection Equipment		61003	$350,000	1.205	$421,750	1.253	$438,550	1.283	$449,050
61.0408	Coal Cars (297)			$16,930,000	1.205	$20,400,650	1.253	$21,213,290	1.283	$21,721,190
61.0410	Pneumatic Material Handling		61007	$27,000	1.205	$32,535	1.253	$33,831	1.283	$34,641
61.1001	Chimney	F&E	61008	$4,612,000	1.205	$5,557,460	1.253	$5,778,836	1.283	$5,917,196
61.1201	Cranes & Hoists		61009	$319,000	1.205	$384,395	1.253	$399,707	1.283	$409,277
61.1601	Passenger Elevators	F&E	61011	$359,000	1.205	$432,595	1.253	$449,827	1.283	$460,597
61.1803	Metal Wall Panel	F&E	61012	$1,559,000	1.205	$1,878,595	1.253	$1,953,427	1.283	$2,000,197
61.2005	Duct Expansion Joints		61013	$635,000	1.205	$765,175	1.253	$795,655	1.283	$814,705
61.2006	Duct Dampers		61014	$1,733,000	1.205	$2,088,265	1.253	$2,171,449	1.283	$2,223,439
61.3801	Breeching and Ducts		61019	$3,332,000	1.205	$4,015,060	1.253	$4,174,996	1.283	$4,274,956
61.3802	Coal Silos		61020	$402,000	1.205	$484,410	1.253	$503,706	1.283	$515,766
61.4001	Structural Steel-Major Fac.	F&E	61021	$23,350,000	1.205	$28,136,751	1.256	$29,330,638	1.312	$30,643,443
61.4002	STR STL-Coal HND,YD		61022	$573,000	1.205	$690,465	1.253	$717,969	1.283	$735,159
	Subtotal Structural Procurement			$55,338,000		$66,682,291		$69,411,602		$71,684,047
62.0201	Particulate Removal Equip	F&E	61024	$17,780,000	1.205	$21,424,900	1.253	$22,278,340	1.283	$22,811,740
62.0202	Flue Gas Scrubber & SLG COND	F&E	61025	$26,955,000	1.205	$32,480,775	1.253	$33,774,615	1.283	$34,583,265
62.0401	Air Compressors		61027	$135,000	1.205	$162,675	1.253	$169,155	1.283	$173,205
62.0405	Carbon Dioxide Supply		61028	$80,000	1.205	$96,400	1.253	$100,240	1.283	$102,640
62.0601	Cooling Tower	F&E	61029	$13,525,000	1.205	$16,297,625	1.253	$16,946,825	1.283	$17,352,575
62.0801	Fire Protection Equip		61030	$182,000	1.205	$219,310	1.253	$228,046	1.283	$233,506
62.0805	Fire Suppression Systems	F&E	61031	$632,000	1.205	$761,560	1.253	$791,896	1.283	$810,856
62.1001	Turbine Generator	F&E	61032	$32,760,000	1.205	$39,475,800	1.253	$41,048,280	1.283	$42,031,080
62.1201	Air Preheating Coils		61034	$100,000	1.205	$120,500	1.253	$125,300	1.283	$128,300
62.1202	Auxiliary Cooling Heat Exch.		61035	$354,000	1.205	$426,570	1.253	$443,562	1.283	$454,182
62.1203	Condenser and Auxiliary Equip		61036	$1,600,000	1.205	$1,928,000	1.253	$2,004,800	1.283	$2,052,800
62.1204	Condenser Tubes		61037	$848,000	1.205	$1,021,840	1.253	$1,062,544	1.283	$1,087,984
62.1205	Deaerator		61038	$344,000	1.205	$414,520	1.253	$431,032	1.283	$441,352
62.1206	Feedwater Heaters		61039	$2,283,000	1.205	$2,751,015	1.253	$2,860,599	1.283	$2,929,089
62.1211	Fuel Oil Heaters		61041	$56,000	1.205	$67,480	1.253	$70,168	1.283	$71,848
62.1801	Ash Handling System		61043	$4,832,000	1.205	$5,822,560	1.253	$6,054,496	1.283	$6,199,456
62.2001	Boiler Feed Pump Turbine		61044	$1,657,000	1.205	$1,996,685	1.253	$2,076,221	1.283	$2,125,931
62.2201	High Pressure Fabricated Pipe		61045	$4,561,000	1.205	$5,496,005	1.253	$5,714,933	1.283	$5,851,763
62.2203	Ash Sluice Pipe		61046	$121,000	1.205	$145,805	1.253	$151,613	1.283	$155,243
62.2205	Circulating Water Pipe		61047	$1,410,000	1.205	$1,699,050	1.253	$1,766,730	1.283	$1,809,030
62.2403	Expansion Joints-Rubber		61049	$31,000	1.205	$37,355	1.253	$38,843	1.283	$39,773
62.2408	Pipe Supports		61050	$535,000	1.205	$644,675	1.253	$670,355	1.283	$686,405
62.2414	Steam Vent Silencers		61051	$15,000	1.205	$18,075	1.253	$18,795	1.283	$19,245
62.2602	Boiler Feed Pumps (Incl Startup)		61052	$1,774,000	1.205	$2,137,670	1.253	$2,222,822	1.283	$2,276,042
62.2603	Circulating Water Pumps		61054	$586,000	1.205	$706,130	1.253	$734,258	1.283	$751,838
62.2604	Condensate Pumps		61055	$580,000	1.205	$698,900	1.253	$726,740	1.283	$744,140
62.2607	Fire Pumps		61056	$37,000	1.205	$44,585	1.253	$46,361	1.283	$47,471
62.2610	Oil Pumps		61057	$30,000	1.205	$36,150	1.253	$37,590	1.283	$38,490
62.2614	Vertical Water Pumps		61058	$293,000	1.205	$353,065	1.253	$367,129	1.283	$375,919
62.2615	General Service Pumps		61059	$229,000	1.205	$275,945	1.253	$286,937	1.283	$293,807
62.2802	Lube Oil Filters		61060	$20,000	1.205	$24,100	1.253	$25,060	1.283	$25,660
62.3001	Auto Flushing Type Water Str.		61061	$50,000	1.205	$60,250	1.253	$62,650	1.283	$64,150
62.3201	Air Conditioning Equipment		61062	$47,000	1.205	$56,635	1.253	$58,891	1.283	$60,301
62.3206	Ventilating Fans		61063	$229,000	1.205	$275,945	1.253	$286,937	1.283	$293,807
62.3401	Steam Generator	F&E	61064	$52,780,100	1.205	$63,600,021	1.253	$66,133,465	1.283	$67,716,868

EXHIBIT NO. 12

WITNESSES: WINDISCH

DESCRIPTION: INTERROGATORY 24
S02 REMOVAL CURRENT AND PROJECTED

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 12
COMPANY/
WITNESS: Windisch
DATE: 6/18/91

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 24

24\. Q. What is the current percent of sulphur dioxide removal per 1000 BTU's of the existing Stanton 1 Unit and the projected percent removal for the Stanton 2 unit?

A. The Stanton 1 Unit is designed to burn a wide range of coals and still meet New Source Performance Standards (NSPS) for all of these coals. For the higher sulfur coals, this requires the removal of a minimum of 90 percent of the SO_2. The facility has been tested on high sulfur coal and is capable of this removal rate with the addition of adipic acid to assist in the scrubbing process. For the coal which has normally been burned in Stanton 1, the NSPS requires a minimum of 70 percent removal of SO_2. OUC has been consistently exceeding this requirement.

The proposed BACT emission rate for Stanton 2 is 0.32 lb/MBtu on a 30-day rolling average basis. The proposed 3-hour and 24-hour emission limits are 0.85 lb/MBtu and 0.67 lb/MBtu, respectively. These emissions compare to the Stanton 1 2-hour emission limit of 1.2 lb/MBtu and a 3-hour emission limit of 1.14 lb/MBtu.

The actual percent removal required to meet the proposed emission rates for Unit 2 will vary with the coal being burned. The facility is being designed to burn a wide range of coals to repeat the successful fuel procurement approach employed with Unit 1. The design basis coal for Stanton 2 would have a 2.5 percent sulfur content. Coals near this level will require removal rates in excess of 90 percent to achieve the proposed BACT emission rate.

EXHIBIT NO. 13

WITNESSES: WINDISCH

DESCRIPTION: INTERROGATORY 28
CAPITAL COST ESTIMATE COAL CARS

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 13
COMPANY/ WITNESS: Windisch
DATE: 6/18/91

Table 1A.2.3-2
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 1991 $	1-1-97 Commercial Operation Dollar Total
61.0403	Bulk Materials Handling FUR	61002	867,200	1,026,593
	ERECT	61002	306,700	363,072
61.0405	Dust Collection Equipment	61003	385,000	455,764
61.0408	Coal Cars (297) reduced to (198)		13,086,000	14,988,177
61.0410	Pneumatic Material Handling	61007	29,700	35,159
61.1001	Chimney FUR	61008	2,134,600	2,536,230
	ERECT	61008	2,100,500	2,532,602
61.1201	Cranes & Hoists	61009	350,900	407,847
61.1601	Passenger Elevators FUR	61011	243,428	288,171
	ERECT	61011	121,659	144,020
61.1803	Metal Wall Panel FUR	61012	1,112,751	1,298,091
	ERECT	61012	473,327	552,164
61.2005	Duct Expansion Joints	61013	698,500	826,886
61.2006	Duct Dampers	61014	2,466,000	2,919,256
61.3801	Breeching and Ducts	61019	3,665,200	4,338,872
61.3802	Coal Silos	61020	W 61.4001	N/A
61.4001	Structural Steel-Major Fac.	61021	6,599,160	7,558,412
	FIRM PORTION	61021	12,493,243	14,500,840
61.4002	Str Stl-Coal Hnd,Yd	61022	W 61.4001	N/A
	Subtotal Structural Procurement		47,133,868	54,772,155
62.0201	Particulate Removal Equip FUR	61024	10,564,000	12,414,278
	ESC PORTION-ERECT	61024	5,053,000	6,070,165
	FIRM PORTION-ERECT	61024	2,828,394	3,477,000
62.0202	Flue Gas Scrubber FUR	61025	14,402,000	16,677,993
62.0203	Sludge Conditioner FUR	61026	1,780,316	2,115,287
	ERECT	61026	598,309	724,040
62.0401	Air Compressors	61027	154,000	181,638
62.0405	Carbon Dioxide Supply	61028	88,000	105,327
62.0601	Cooling Tower FUR	61029	6,832,705	7,970,759
	ERECT	61029	4,470,420	5,370,312
62.0801	Fire Protection Equip	61030	200,200	237,868
62.0805	Fire Suppression Systems FUR	61031	380,209	463,496
	ERECT	61031	252,788	302,562

EXHIBIT NO. 14

WITNESSES: WINDISCH

DESCRIPTION: INTERROGATORY 31
HEAT RATE ET AL

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 14
COMPANY/ WITNESS: Windisch
DATE: 6/18/91

31. Q. Please provide a summary filing showing the anticipated capacity rate, heat rate, outage rate, forced outage rate, equivalent availability, fuel efficiency, etc. of the proposed plant based on high and low sulfur coal use.

A. Stanton 2 is designed for operation with both high and low sulfur coal. A summary of the requested design parameters is provided below.

Anticipated net plant output	440 MW
Forced outage rate	4%
Equivalent availability	83%
Full load net heat rate	9,740 BTU/KWH
Boiler efficiency*	89.07

*At 100% load firing Appalachian design coal

The above ratings are based on scrubber operation at a 92 percent removal rate which would be required for the BACT design basis coal with 2.5 percent sulfur to achieve the proposed BACT emission rate of 0.32 lb/MBtu SO_2. The use of a coal with higher than 2.5 percent sulfur would require a higher percent removal to meet the proposed 0.32 lb/MBtu SO_2 emission rate. A higher than 92 percent removal rate requirement will result in an increased forced outage rate. The economic evaluations in the Supplemental Site Certification Application are based on a higher cost low sulfur coal with 0.7 to 1.0 percent sulfur. The medium sulfur coal prices projected in the application are based on a 1.5 to 2.0 percent sulfur coal. Since both coals are lower in sulfur than 2.5 percent, they would require less than 92 percent removal to achieve the 0.32 lb/MBtu emission rate and the above deisgn parameters would be applicable to both coals.

15

1B.14.0 Consequences of Delay

OUC will experience significant adverse consequences if Stanton 2 is not constructed or is delayed. As indicated in Subsection 1B.11.7, Strategy B including ownership of a 330 MW share of Stanton 2 represents the least cost alternative available to OUC. Strategy B with OUC ownership of a 330 MW share of Stanton 2 represents a 1991 cumulative present worth savings of $220 million or 4.8 percent over Strategy D, next lowest cost expansion plan based on installing a combined cycle. In addition, if OUC is able to sell a portion of the capacity from Stanton 2 during the years when the additional capacity is not required to meet reserve margin requirements, OUC's cost for Stanton 2 will be significantly reduced. Subsection 1B.16.0 indicates that the sale of 110 MW of Stanton 2 capacity from 1997 to 2008 at the Indiantown Cogeneration Project power sales contract price would result in a 1991 cumulative present worth savings to OUC of $163 million. If Stanton 2 were not constructed, OUC would have to install a more expensive means of meeting their customers' loads and would not have the opportunity to further reduce rates to their customers through power sales.

The installation of Stanton 2 by OUC will provide the benefit of lower cost energy to the Florida Municipal Power Pool. The City of Lakeland and FMPA will share the savings associated with the lower cost energy associated with Stanton 2. If Stanton 2 is not constructed or is delayed, these benefits will not be available.

The installation of Stanton 2 will also provide the opportunity for additional economy sales on the FCG Energy Broker. The utilities purchasing the economy energy and OUC will share the savings from these Broker sales. If Stanton 2 is not installed or is delayed, the benefits from these Broker sales would not be available to the rate payers of the state.

The installation of Stanton 2 complies with the legislative findings and intent of the Florida Energy Efficiency and Conservation Act. Stanton 2 will serve to reduce natural gas usage and conserve expensive resources, particularly petroleum fuels used in the production of electricity. At a 70 percent capacity factor, Stanton 2 will displace the equivalent of 26,000,000 MCF of gas or 4.2 million barrels of oil annually.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 15
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

If Stanton 2 were not installed, these fuels would be consumed in meeting the electrical energy requirements of the state.

If Stanton 2 were to be delayed, electric system reliability would be reduced for OUC and the state as a whole. If Stanton 2 were delayed, OUC's reserve margin would drop below acceptable levels and reliable service to OUC's customers would be impaired. OUC's reserve margin for the 1998-99 winter period would decrease to 10.4 percent for normal weather and to only 3.2 for extreme weather including peak demand reductions for additional demand-side management programs. If extreme weather occurred, OUC would have only 19 MW of reserves at the time of the 1998-99 peak and would not be able to supply firm load if any of OUC's generating units were unavailable other than OUC's 13 MW share of Crystal River 3. For comparison, the severe power outages in December 1989 occurred when Peninsular Florida had a 23 percent reserve margin based on normal weather and an actual reserve margin based on the extreme weather load of 5.3 percent. Without the addition of Stanton 2, the reserve margin for Peninsular Florida is projected to dip to 11 percent for the 1998-99 peak. A reserve margin of that level would jeopardize the entire grid.

A detailed evaluation was conducted to determine the cost impact of delaying OUC's 330 MW share of Stanton 2 one year to January 1, 1998. The evaluation was based on the assumption that The Florida Power Corporation stratified partial requirements peaking power available to KUA could be purchased when needed by OUC. The evaluation also assumes a 110 MW unit power sale from Stanton 2 from commercial operation through 2008, at which time OUC requires the capacity to meet the 15 percent reserve margin requirement. A detailed capital cost estimate of Stanton 2 was developed to assess the impact of delaying commercial operation until 1998. The 1991 cumulative present worth comparative costs for the evaluation period from 1991 through 2020 are shown below.

Commercial Operation	Cumulative Present Worth Comparative Cost $million	Cumulative Present Worth Comparative Cost Percent
January 1, 1997	4,560	Base
January 1, 1998	4,569	2

Delaying OUC's 330 MW share of Stanton 2 one year results in an increase in the cumulative present worth comparative cost to OUC of approximately $9 million or 2 percent. A significant portion of the increased expense is due to the higher cost of producing energy without Stanton 2 in the system mix. In addition, the other benefits to OUC, KUA, FMPA, and Peninsular Florida described above would be lost for that year.

Corrections to the Curtis H. Stanton Energy Center Unit 2 Supplemental Site Certification Application

1. On Page 1A.3.3-4, Line 21, change "(FLG)" to "(FCG)."
2. On Page 1A.3.3-16, Line 11, change "6.99" to "6.94."
3. On Page 1A.4.2-3, move the combinations for 1994 up one line.
4. On Page 1B.7.1-1, Line 22, change "reserve margin would be more typical" to "reserve margin is more typical."
5. On Page 1B.7.1-2, Line 14, change "shape changes, it" to "shape changes and the probabilistic nature of generating unit forced outages, it."
6. On Page 1B.7.1-2, Line 18, change "0.3 percent. Subsequent" to "0.3 percent on an unassisted basis. Subsequent."
7. On Page 1B.7.1-2, Line 20, change "higher 0.5 EUE is" to "higher 0.5 percent EUE is."
8. On Page 1B.10.1-1, Line 11, change "Plan A" to "Strategy A."
9. On Page 1B.10.4-1, Line 2, change "Plan D" to "Strategy D."
10. On Page 1B.11.1-1,Line 26, change "developed three load forecasts" to "developed three hourly load forecasts."
11. On Page 1B.11.3-2, Line 4, change "$kW" to "$/kW."
12. On Page 1B.11.3-2, Line 9, change "Total Installed Cost" to "Total Installed Cost (1-1-97)."

13. On Pages 1B.11.4-2 through 1B.11.4-7, delete the "(MW)" from the columns labeled "Peak" and "Curtailable Rates" and add "(MW)" below the table title.

14. On Page 1B.11.5-1, Line 4, change "$4,660 million" to "$4,559 million."

15. On Page 1B.11.5-1, Line 7, change "2018" to "2019."

16. On Page 1B.11.5-2 and 1B.11.5-3, delete the "(MW)" from the columns labeled "Peak" and "Curtailable Rates" and add "(MW)" below the table title.

17. On Page 1B.11.6-1, Line 22, change "strategy" to "strategies."

18. On Pages 1B.11.6-4 and 1B.11.6-5, delete the "(MW)" from the columns labeled "Peak" and "Standby Generator" and add "(MW)" below the table title.

19. On Page 1B.11.6-4 and 1B.11.6-5, change "Standby Generator" to "Curtailable Rates."

20. On Page 1B.13.0-1, Line 25, change "on the Broker." to "on the Florida Energy Broker."

21. On Page 1B.13.0-1, Line 26, change "firms" to "firm."

22. Delete Pages 1B.17.0-1 through 1B.17.0-5 and replace them with the attached Pages 1B.17.0-1 through 1B.17.0-6.

1B.17.0 Analysis of 1990 Clean Air Act Amendments

Title IV of the Clean Air Act amendments of 1990 require that all existing units greater than 25 MW and all new units comply with emission limitations. The total SO_2 emissions from a unit in one year cannot be greater than the total number of allowances allocated to that unit, unless allowances are acquired from another source. It is important to note that any additional generating capacity (such as Stanton 2) will not be granted any allowances. Emissions from new sources must be offset by reductions of emissions from other units in the system or through the purchase of allowances.

This subsection discusses the expected impacts of Title IV of the Clean Air Act amendments of 1990 on OUC's ability to provide the allowances required to maintain electrical generation at Stanton 2. This discussion is not a comprehensive consideration of the 1990 Clean Air Act as it affects the OUC system. It does not address NO_x limitations, CEM installation, or other requirements of the Act. The intent of this subsection is only to verify that sufficient SO_2 allowances will exist within the OUC system to provide for the emission requirements of Stanton 2.

The information used in the calculation of allowances available to OUC was taken from the EPA's National Allowance Data Base, version 1.0. The information provided in the data base forms the basis on which EPA will determine the allowances that will be granted to each unit. Therefore, it is important that this information be checked for accuracy, and that any discrepancies between the data base and existing records be identified.

The provisions of the Clean Air Act amendments of 1990 used to determine allowances can differ depending on the size of a unit, its SO_2 emission rate, the type of fuel fired in the unit, and other factors. In addition, several options for calculating the basic Phase II allowances may exist for a unit, depending on historical SO_2 emissions and unit operation, utility size, startup dates, and other information. Section 416(b) requires that 2.8 percent be withheld from all basic Phase II allowances allocated. Also, in order to maintain emissions from utility units below the 8.9 million tons per year cap stated in Section 403(a), EPA has the authority to reduce the basic Phase II allowances granted to all units on a pro rata basis. Consequently, the allowances calculated in this analysis may be increased or decreased in order to accommodate the overall objectives of the legislation.

The Indian River Combustion Turbines A and B are simple cycle combustion turbines and as such are not considered existing units under Section 402(8). The Indian River Combustion Turbines C and D will be considered existing units; however, since they will primarily burn natural gas and allowances required by Indian River C and D will be small in comparison to the scope of this analysis, these allowances have not been included.

Indian River 1 falls under the jurisdiction of Section 405(e), which pertains to oil- and gas-fired units with SO_2 emissions equal to or greater than 0.6 lb/Mbtu and less than 1.2 lb/MBtu. Indian River 1's allowances pursuant to 405(e) are calculated as

baseline FBR * actual 1985 SO_2 emission rate * 1.2 /2000

or

1,665,300 MBtu * 0.9869 lb SO_2/MBtu * 1.2 * (1 ton/2000 lb).

This results in 986 tons/year, reduced by 2.8 percent to 958 tons/year.

Allowances for Indian River 2 and 3 are determined by Section 405(f), which grants allowances to oil- and gas-fired units which emit less than 0.6 lb/MBtu SO_2. Allowances for Indian River 2 are calculated as

baseline FBR * 0.6 lb/MBtu * 1.2 / 2000

or

4,018,300 MBtu * 0.6 lb SO_2/MBtu * 1.2 * (1 ton/2000 lb).

This provides 1447 tons/year reduced by 2.8 percent to 1406 tons/year. Allowances for Indian River 3 are calculated as

9,951,700 MBtu * 0.6 lb SO_2/MBtu * 1.2 * (1 ton/2000 lb)

or 3,583 tons/year reduced by 2.8 percent to 3,482 tons/year. Indian River Units 2 and 3 will receive additional allowances pursuant to Section 405(f)(2), which grants allowances to units serving one city and one county. These additional allowances have not been included in this evaluation because the exact amount of allowances that will be granted is not known and because the amount of allowances granted will be minor in comparison to the scope of this analysis.

McIntosh 3 falls under the requirements of Sections 405(d)(1), 405(d)(3)(A), and 405(d)(4). Section 405(d)(4) provides the most allowances to McIntosh 3, and has been used in this analysis. Section 405(d)(4) provides allowances to coal-fired units below 1.2 lb/MBtu which commenced commercial operation between January 1, 1981 and December 31, 1985. Allowances are calculated as

annual fuel consumption at 65% cf * 1985 allowable emission rate /2000

or

18,913,500 MBtu * 1.2 * (1 ton/2000 lb) or

11,348 tons/year reduced by 2.8 percent to 11,030 tons/year are provided. The annual fuel consumption at 65 percent capacity factor has been determined as a ratio from the fuel burn rate at 60 percent capacity factor as reported in the EPA data base.

Allowances for Stanton 1 will be governed by Section 405(g)(1), which allocates allowances to units that commenced operation between January 1, 1986 and December 31, 1990. Allowances are allocated as

annual fuel consumption at 65% cf * units allowable emission rate / 2000;

however, there are a number of uncertainties with respect to how Section 405(g)(1) will be administered. It is likely that some annualization factor will be applied to Stanton 1's 1.14 lb SO_2/MBtu maximum three hour emission rate. For evaluation purposes the annualization factor is assumed to be 95 percent as listed on the EPA data base. Allowances are calculated as

annual fuel consumption at 65% cf * allowable emission rate * annualization factor/2000

or

24,346,183 * 1.14* .95* (1 ton/2000 lb.) or

13,183 tons/year reduced by 2.8 percent to 12,814 tons/year are provided. The annual fuel consumption at 65 percent capacity factor has been determined as a ratio from the fuel burn rate at 60 percent capacity factor as reported in the EPA data base.

OUC units may receive a larger number of allowances pursuant to Section 405(1)(1), which governs units in high growth states. These additional allowances have not been included in this evaluation because the exact amount of allowances that will be granted is not known and because the amount of allowances will be minor in comparison to the scope of this analysis.

While there is still significant uncertainty with respect to the implementation of the Clean Air Act amendments of 1990, the OUC allowances shown in Table 1B.17.0-1 represent a reasonable basis for this evaluation.

To determine the allowances required, OUC's system was modeled under the base case expansion plan including the additional demand-side management programs described in Subsection 1B.11. While the Indian River Units were assumed to burn 100 percent natural gas in Subsection 1B.11 because it was the least cost fuel, when evaluating SO_2 allowances, the Indian River Units were assumed to burn 100 percent oil as the worst possible case. Sulfur content for the Indian River fuel oil is assumed to be equal to the average for that burned in 1989 as reported in Cost and Quality of Fuels for Electric Utility Plants 1989. The sulfur content of coal for Stanton 1 and 2 and McIntosh 3 is assumed to be that burned in 1989 as shown in Table 1A.3.3-5. The assumed sulfur content is summarized below.

Unit	Sulfur percent
Stanton 1 and 2	0.74
McIntosh	1.29
Indian River	1.41

An 85 percent removal rate is assumed for Stanton 1 and 2 and 86 percent for McIntosh 3.

Table 1B.17.0-2 presents projected SO_2 emissions for OUC's system compared to the OUC's estimated allowances. As shown in Table 1B.17.0-2, OUC is projected to have sufficient allowances for each year of the planning period.

Table 1B.17.0-1
Allowance Data

Unit	Ownership percent	1985 SO_2 Emission Rate lb/MBtu	Baseline Fuel Burn Rate MBtu/yr	Permitted SO_2 Emission Rate lb/MBtu	Basic Phase II SO_2 Allowances tons
Indian River 1	100.0	.9869	1,665,300	2.75	958
Indian River 2	100.0	.5467	4,018,300	2.75	1,406
Indian River 3	100.0	.0687	9,951,700	2.75	3,482
McIntosh 3	40.0	.490	16,442,700	1.20	11,030
Stanton 1	68.6	-	24,346,183	1.14	12,814

	tons	tons
2000	11,049	7 041
2001	12,292	12,839
2002	13,129	17,800
2003	12,877	23,013
2004	14,123	26,980
2005	14,408	30,662
2006	14,575	32,665
2007	15,508	35,247
2008	16,695	36,642
2009	16,485	38,247
2010	11,179	45,158
2011	11,699	51,549
2012	12,096	57,543
2013	13,412	62,221
2014	14,574	65,737
2015	9,278	74,549
2016	10,293	82,346
2017	8,888	91,548
2018	9,262	100,376
2019	9,677	108,789
2020	9,988	116,891

* Assuming 18,090 allowances per year.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness: Myron R. Rollins
Exhibit No. __ (MRR-2)
Page 1 of 1

OPTIMAL DEMAND SIDE EXPANSION
CUMULATIVE PRESENT WORTH
EXPECT 2 (E201ALO.WK)
WITH ALLOWANCE COSTS INCLUDED

	OUC PRODUCTION COSTS				Levelized Capital Costs											Total Revenue Requirements	
Year	Fuel	O&M	Startup	Total	STANTON 2 1997	675/2 pc 2010	675/2 pc 2015	675/2 pc 2017	192 ct 2020	STANTON 2 ALLOWANCES	COMMER LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	1991 Cumulative Present Worth
	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000	$1000
														106.375			
1991	89,683	618	297	90,598							0.00	0.00	0.00		0	90,598	90,598
1992	103,348	673	393	104,414							0.00	0.00	0.00		0	104,414	189,153
1993	109,336	839	403	110,578							237.56	236.26	0.00		473	111,050	285,085
1994	121,970	976	432	123,377							245.10	247.60	0.00		493	123,870	386,124
1995	135,466	991	444	136,902							252.92	261.26	0.00		514	137,417	490,841
1996	157,744	1,265	483	159,492							261.03	279.71	0.00		541	160,033	604,793
1997	153,081	10,457	729	164,268	36,253					2,113	269.45	294.64	0.00	106.375	39,117	203,385	740,079
1998	171,385	11,129	774	183,288	36,253					2,162	278.18	308.53	0.00	106.375	39,189	222,478	878,365
1999	187,125	11,717	870	199,712	36,253					2,381	287.25	324.68	0.00	106.375	39,412	239,124	1,017,215
2000	210,070	12,373	967	223,410	36,253					2,385	296.65	337.67	0.00	106.375	39,459	262,869	1,158,839
2001	236,208	13,007	955	249,171	36,253					2,246	306.41	344.18	0.00	106.375	39,336	288,508	1,306,080
2002	258,956	13,657	1,079	273,691	36,253					2,454	316.54	343.01	0.00	106.375	39,553	313,244	1,454,452
2003	281,664	14,407	1,084	297,155	36,253					2,448	327.05	360.62	0.00	106.375	39,583	336,738	1,603,465
2004	311,954	15,126	1,146	328,227	36,253					2,337	337.97	381.26	0.00	106.375	39,495	367,722	1,755,502
2005	337,711	15,832	1,267	354,809	36,253					2,511	349.30	391.40	0.00	106.375	39,691	394,500	1,907,896
2006	368,460	16,755	1,389	386,614	36,253					2,526	361.05	402.49	0.00	106.375	39,729	426,343	2,061,774
2007	404,714	17,525	1,461	423,700	36,253					2,377	373.27	419.70	0.00	106.375	39,600	463,300	2,210,011
2008	454,699	18,538	1,511	474,749	36,253					2,588	385.94	436.82	0.00	106.375	39,850	514,599	2,380,145
2009	493,329	19,622	1,580	514,531	36,253					2,601	399.10	459.59	0.00	106.375	39,889	554,419	2,543,352
2010	459,221	39,884	2,072	501,177	36,253	71,150				2,162	0.00	656.07	0.00	106.375	110,407	611,585	2,711,562
2011	506,211	41,980	1,960	550,151	36,253	71,150				2,322	0.00	413.72	0.00	106.375	110,324	660,475	2,881,207
2012	564,963	44,455	2,201	611,618	36,253	71,150				2,339	0.00	737.67	0.00	106.375	110,586	722,204	3,054,704
2013	633,236	46,917	2,371	682,523	36,253	71,150				2,243	0.06	454.68	0.00	106.375	110,286	792,810	3,232,562
2014	714,957	49,437	2,583	766,977	36,253	71,150				2,434	0.00	814.00	0.00	106.375	110,837	877,814	3,418,534
2015	652,516	74,699	3,041	730,256	36,253	71,150	89,665			2,163	0.00	499.56	0.00	106.375	199,917	929,173	3,598,489
2016	739,957	78,070	3,220	821,248	36,253	71,150	89,665			2,089	0.00	898.73	0.00	106.375	199,242	1,020,490	3,786,200
2017	737,425	107,127	4,916	849,468	36,253	71,150	89,665	96,025		1,791	0.00	540.98	0.00	106.375	295,419	1,144,887	3,980,912
2018	824,983	112,443	4,562	941,988	36,253	71,150	89,665	96,025		1,969	0.00	982.75	0.00	106.375	296,041	1,238,028	4,178,646
2019	907,452	118,158	4,760	1,030,371	36,253	71,150	89,665	96,025		1,863	0.00	604.15	0.00	106.375	295,547	1,325,918	4,376,508
2020	980,991	130,719	5,689	1,117,398	36,253	71,150	89,665	96,025	16,197	2,064	0.00	1096.38	0.00	106.375	312,437	1,429,835	4,575,863

EXHIBIT NO.________________

WITNESSES: ROLLINS

DESCRIPTION: INTERROGATORY 35
IMPACT CLEAN AIR AMENDMENTS

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. ~~23~~ 18
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

35\. Q. How did the Clean Air Act Amendments of 1990 impact the fuel price forecasts? How did the CAA impact OUC's decision criteria for selecting a generating technology?

A. The 1990 Clean Air Act Amendments were considered in projecting fuel prices. The Amendments should place greater demands on high quality, low sulfur coal. The coal price projections in the 1990 Annual Energy Outlook were adjusted to reflect increases in demand. A consensus of various opinions indicate that low sulfur coal prices should be $1.37/Mbtu fob mine in 1989 dollars in the year 2000 when Phase II begins. This price is reflected in the low sulfur coal projections.

OUC has adequate allowances from existing units to provide for the projected needs through the planning period. The impact of the 1990 Clean Air Act Amendments on coal prices was assessed as described above. It is realistic to assume that the 1990 Clean Air Act Amendments will also tend to cause natural gas prices to increase. However, the possible effect on natural gas prices was not included in any evaluations.

The 1990 Clean Air Act Amendments impact was included on low sulfur coal prices and was not included on natural gas prices. Since the Stanton 2 project was the least cost alternative, there was no impact on the selection of generation technology.

EXHIBIT NO.________________

WITNESSES: ROLLINS

DESCRIPTION: INTERROGATORY 40
UPS SALES - VALUE OF SO2 ALLOWANCES

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 19
COMPANY/
WITNESS: Rollins
DATE: 6/18/91

40. Q. In your scenario of a UPS sale of 110 MW of Stanton 2, did you consider a value of the allowances generated pursuant to the Clean Air Act Amendments, needed for that 110 MW? Who will pay for these allowances?

A. For the scenario of a UPS of 110 MW of Stanton 2, no specific costs or values were identified with respect to the allowances generated. A value of the allowances generated pursuant to the 1990 Clean Air Act Amendments will be considered as part of a UPS sale once it is finalized.

EXHIBIT NO.________________

WITNESSES: ROLLINS

DESCRIPTION: INTERROGATORY 41
TOXICS SECTION CLEAN AIR ACT

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 20
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

41. Q. a. In Section 301(n)(1)(A) & (B) of the Clean Air Act, the Administrator will perform a study of toxics as a result of emissions by electric utilities. If the Administrator finds that the electric utilities are emitting toxics and mercury levels that require alternative/additional control strategies, what effect will this decision have on your original technology screening analysis for Stanton 2?
b. Please provide the capital and O&M costs in $/kW for any generation technology changes resulting from (a) above.

A. The EPA will not be completing its study under 301(n)(1)(A) & (B) in time to accurately reflect the results in the Stanton 2 decision. But if it is assumed that EPA determines that coal fired plants are contributing unacceptable levels of toxics or mercury, the toxics emitted in particulate form can be controlled by particulate removal. Both Stanton 1 and 2 have advanced particulate removal and hence would not be subject to any new control technologies.

Some of the mercury can remain in gaseous form and pass through the particulate control device. The most effective control for mercury is the cooling of the flue gas stream to facilitate its condensation to particulate form. The most effective means of cooling the flue gas is with a wet scrubber with which Stanton 1 is equipped, and which is proposed for Stanton 2. Stack testing on Stanton 1 has shown mercury control to be approximately 90 percent effective and therefore these units are not a major contributor of mercury. Consequently the study and actions of the EPA are not expected to have any impact on either Stanton 1 or 2. Thus regardless of the EPA decision, the study of toxics is not expected to have any effect on OUC's original technology screening analysis for Stanton 2 and no changes to the capital and O&M costs for Stanton 2 are appropriate.

EXHIBIT NO.________________

WITNESSES: ROLLINS

DESCRIPTION: INTERROGATORY 42
SELECTIVE CATALYTIC REDUCTION

STAFF: TAYLOR

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 21
COMPANY/
WITNESS: Rollins
DATE: 6/18/91

42. Q. For the following questions, assume that selective catalytic reduction (SCR) technology is required by FDER and/or the EPA for environmental compliance.

a. What is OUC's opinion as to the effect such a decision would have on your original technology screening analysis? That is, would the environmental compliance measures originally assumed by the Company for, e.g., a pulverized coal unit, require changing? If not, explain why. If so, please detail the adjustments made to each generation technology type to meet the newly-anticipated environmental standards, and rerun and provide the results of your technology screening analysis.

b. Please provide the capital and O&M costs in $/kW for any generation technology changes resulting from "a" above. Indicate the incremental or decremental $/kW cost as appropriate of such changes relative to your original assumptions.

A. a. Based on current BACT it is OUC's position that SCR technology is not required by the FDER and/or the EPA for environmental compliance. SCR technology could conceivably reduce NO_x levels below those produced by fluidized bed combustion. For the hypothetical case, it is assumed that SCR would apply to both pulverized coal units and fluidized bed units. The costs are similar to apply SCR technology to pulverized coal and fluidized bed combustion plants. Thus, the economic relationship between pulverized coal and fluidized bed combustion would not change appreciably.

The economic relationship of coal fueled units would change compared to other generation alternatives which were screened, i.e., a combustion turbine unit and combined cycle unit. The exhaust gas from a simple cycle combustion turbine is too hot to utilize present SCR technology. SCR technology was applied to the combined cycle units described in Subsection 1A.5.2.4. To re-screen the Stanton 2 alternative the following costs were added to the base plant costs.

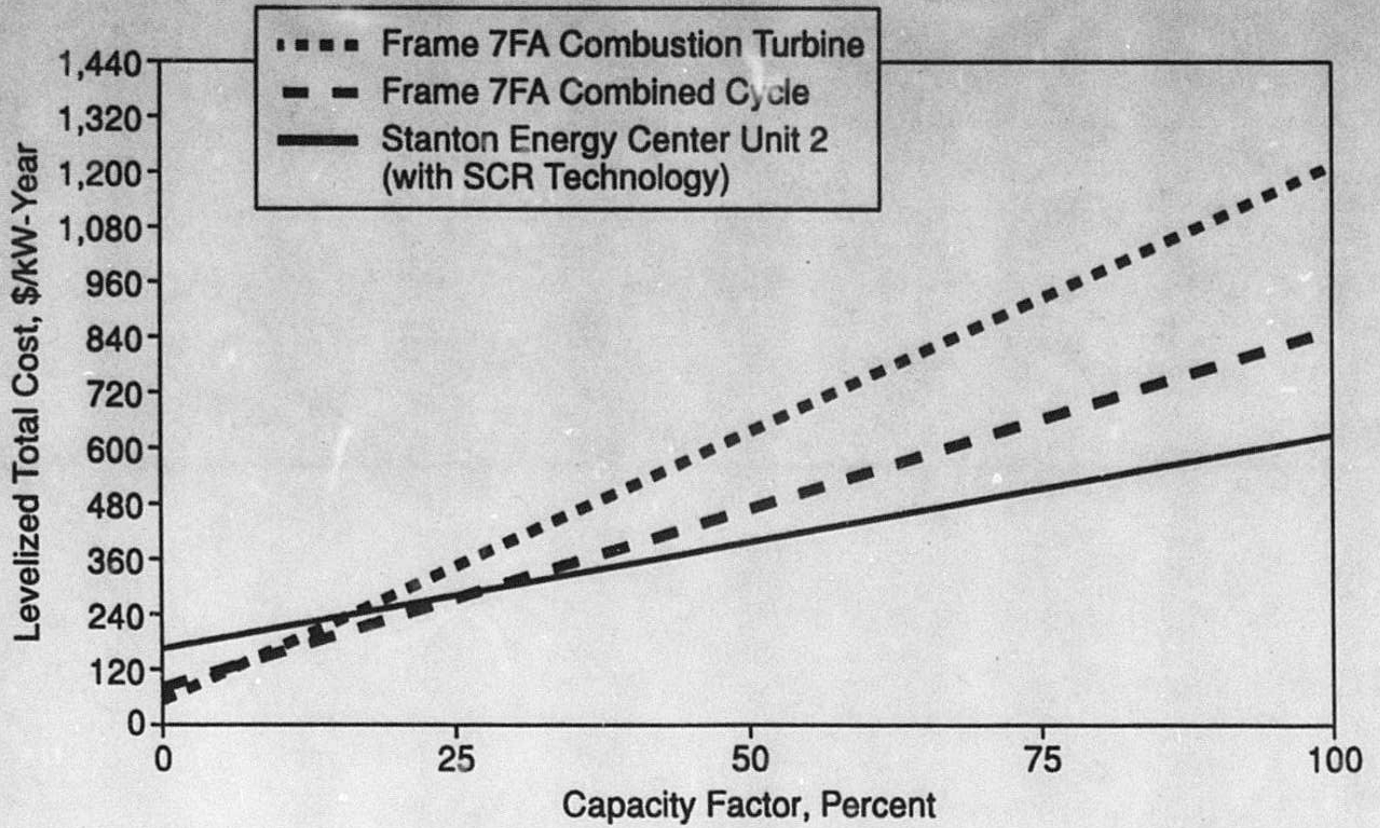
	PC/FBC
SCR Capital Cost ($/kW)	105
Fixed Non-Fuel O&M ($kW/Yr)	1.30
Variable Non-Fuel O&M ($/MWh)	3.00
Heat rate penalty (percent)	1.0

Figure 42-1 presents the results of the re-screening with SCR assumed. Figure 42-1 indicates that Stanton 2 would still be more economical than a combined cycle above 29 percent capacity factor.

b. Please see the capital and O&M costs tabulated in a. above.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 42
Page 3 of 3

FIGURE 42-1
OUC SCREENING CURVES



OUC130

EXHIBIT NO.___________

WITNESS: ROLLINS

DESCRIPTION: COMPARISON OF OUC STANTON 2 WITH
ORLANDO COGEN LIMITED

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 22
COMPANY/
WITNESS: Rollins
DATE: 6/18/91

ORLANDO COGEN LIMITED, L.P. (OCL) EVALUATION VERSUS STANTON 2

Year	Capacity Payment OCL *	Capacity Payment Stanton 2	OCL Generation **	OCL Energy Payment	Stanton 2 Production Costs: Energy Cost	Stanton 2 Production Costs: Variable O&M	Stanton 2 Production Costs: Fixed O&M	Total Cost: OCL	Total Cost: Stanton 2	Savings With Stanton 2
	$/kW-mo	$/kW-mo	MWh	$/MWh	$/MWh	$/MWh	$/kW-mo	$1000	$1000	$1000
1994	12.82		607,383	29.32				28,885		
1995	13.46		607,383	30.82				30,349		
1996	14.15		607,383	32.39				31,899		
1997	14.88	9.15	607,383	34.04	28.19	0.25	2.44	33,532	27,287	6,245
1998	15.83	9.15	607,383	35.78	29.52	0.27	2.62	35,409	28,266	7,143
1999	16.48	9.15	607,383	37.60	30.98	0.28	2.75	37,076	29,263	7,813
2000	17.27	9.15	607,383	39.52	33.42	0.29	2.88	38,925	30,871	8,054
2001	18.16	9.15	607,383	41.54	35.17	0.31	3.01	40,921	32,055	8,866
2002	19.08	9.15	607,383	43.66	37.00	0.32	3.16	43,003	33,300	9,703
2003	20.05	9.15	607,383	45.88	38.94	0.34	3.31	45,190	34,618	10,572
2004	21.08	9.15	607,383	48.23	40.86	0.35	3.46	47,507	35,930	11,577
2005	22.15	9.15	607,383	50.69	43.00	0.37	3.63	49,926	37,384	12,542
2006	23.27	9.15	607,383	53.27	45.25	0.39	3.80	52,461	38,907	13,554
2007	24.48	9.15	607,383	55.98	47.56	0.40	3.98	55,152	40,481	14,671
2008	25.71	9.15	607,383	58.84	49.99	0.42	4.17	57,952	42,131	15,821
2009	27.03	9.15	607,383	61.84	52.63	0.44	4.37	60,915	43,915	16,999
2010	28.40	9.15	607,383	65.00	55.31	0.46	4.58	64,018	45,735	18,282
2011	29.85	9.15	607,383	68.31	58.13	0.49	4.79	67,281	47,650	19,630
2012	31.38	9.15	607,383	71.79	61.14	0.51	5.02	70,716	49,692	21,024
2013	32.98	9.15	607,383	76.46	64.34	0.53	5.26	74,935	51,855	23,080
2014	34.65	9.15	607,383	79.30	67.64	0.56	5.51	78,103	54,090	24,013
2015	36.42	9.15	607,383	83.35	70.99	0.59	5.77	82,092	56,367	25,725
2016	38.27	9.15	607,383	87.60	74.68	0.61	6.05	86,272	58,861	27,411
2017	40.23	9.15	607,383	92.06	78.54	0.64	6.33	90,674	61,470	29,204
2018	42.27	9.15	607,383	96.77	82.61	0.67	6.63	95,298	64,223	31,074
2019	44.44	9.15	607,383	101.69	86.76	0.71	6.95	100,161	67,036	33,125
2020	46.70	9.15	607,383	106.88	91.29	0.74	7.28	105,266	70,092	35,174

* Does not include additional capacity credit for high capacity factor.
** Based on 96.3 percent capacity factor and 72 MW capacity.

EXHIBIT NO.___________

WITNESS: ROLLINS

DESCRIPTION: RESPONSE TO STAFF INTERROGATORY 18

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 23
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

Projected Reliability Levels Including 330 MW of Stanton 2
and Without Additional Demand-Side Management

Winter Season	Total Capacity MW	Peak Demands* MW	Reserve Margin percent	Year	EUE percent
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,077	30.1	1993	0.14
1993-94	1,401	1,111	26.1	1994	0.12
1994-95	1,401	1,144	22.5	1995	0.16
1995-96	1,401	1,177	19.0	1996	0.55
1996-97	1,731***	1,220	41.9	1997	0.23
1997-98	1,731	1,258	37.6	1998	0.15
1998-99	1,731	1,288	34.4	1999	0.09
1999-2000	1,731	1,319	31.2	2000	0.11
2000-01	1,731	1,354	27.8	2001	0.15
2001-02	1,731	1,341	29.1	2002	0.12
2002-03	1,731	1,358	27.5	2003	0.26
2003-04	1,731	1,332	30.0	2004	0.23
2004-05	1,731	1,342	29.0	2005	0.22
2005-06	1,731	1,343	29.0	2006	0.27
2006-07	1,731	1,353	27.9	2007	0.34
2007-08	1,731	1,391	24.4	2008	0.39

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 330 MW capacity addition of Stanton 2.

EXHIBIT NO.___________

WITNESS: ROLLINS

DESCRIPTION: COMPARISON OF OUC STANTON 2 WITH ORLANDO COGEN LIMITED

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 22
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

COMPARISON OF OUC STANTON 2 WITH ORLANDO COGEN LIMITED, L.P.

Contract with Florida Power Corporation

Orlando CoGen's contact capacity and energy payments were compared to costs for Stanton 2. Orlando CoGen was assumed to have a capacity of 72 MW and an annual capacity factor of 96.3 percent as presented in Attachment H Revised 5-28-91 from Docket 910401-EQ, Petition for Approval of Contracts for Purchase of Firm Capacity and Energy by Florida Power Corporation. OUC's Stanton 2 capacity payment, fuel cost, and fixed and variable O&M costs are consistent with information provided in the Supplemental Site Certification Application and the associated production cost modeling.

Total costs are based on a capacity of 72 MW and 607,383 MWh of annual energy production. Stanton 2 provides savings of approximately $6 million in 1997 and $35 million in 2020 based on these assumptions.

ORLANDO COGEN LIMITED, L.P. (OCL) EVALUATION VERSUS STANTON 2

Year	Capacity Payment		OCL Generation **	OCL Energy Payment	Stanton 2 Production Costs			Total Cost		Savings With Stanton 2
	OCL *	Stanton 2			Energy Cost	Variable O&M	Fixed O&M	OCL	Stanton 2	
	$/kW-mo	$/kW-mo	MWh	$/MWh	$/MWh	$/MWh	$/kW-mo	$1000	$1000	$1000
1994	12.82		607,383	29.32				28,885		
1995	13.46		607,383	30.82				30,349		
1996	14.15		607,383	32.39				31,899		
1997	14.88	9.15	607,383	34.04	28.19	0.25	2.44	33,532	27,287	6,245
1998	15.83	9.15	607,383	35.78	29.52	0.27	2.62	35,409	28,266	7,143
1999	16.48	9.15	607,383	37.60	30.98	0.28	2.75	37,076	29,263	7,813
2000	17.27	9.15	607,383	39.52	33.42	0.29	2.88	38,925	30,871	8,054
2001	18.16	9.15	607,383	41.54	35.17	0.31	3.01	40,921	32,055	8,866
2002	19.08	9.15	607,383	43.66	37.00	0.32	3.16	43,003	33,300	9,703
2003	20.05	9.15	607,383	45.88	38.94	0.34	3.31	45,190	34,618	10,572
2004	21.08	9.15	607,383	48.23	40.86	0.35	3.46	47,507	35,930	11,577
2005	22.15	9.15	607,383	50.69	43.00	0.37	3.63	49,926	37,384	12,542
2006	23.27	9.15	607,383	53.27	45.25	0.39	3.80	52,461	38,907	13,554
2007	24.48	9.15	607,383	55.98	47.56	0.40	3.98	55,152	40,481	14,671
2008	25.71	9.15	607,383	58.84	49.99	0.42	4.17	57,952	42,131	15,821
2009	27.03	9.15	607,383	61.84	52.63	0.44	4.37	60,915	43,915	16,999
2010	28.40	9.15	607,383	65.00	55.31	0.46	4.58	64,018	45,735	18,282
2011	29.85	9.15	607,383	68.31	58.13	0.49	4.79	67,281	47,650	19,630
2012	31.38	9.15	607,383	71.79	61.14	0.51	5.02	70,716	49,692	21,024
2013	32.98	9.15	607,383	76.46	64.34	0.53	5.26	74,935	51,855	23,080
2014	34.65	9.15	607,383	79.30	67.64	0.56	5.51	78,103	54,090	24,013
2015	36.42	9.15	607,383	83.35	70.99	0.59	5.77	82,092	56,367	25,725
2016	38.27	9.15	607,383	87.60	74.68	0.61	6.05	86,272	58,861	27,411
2017	40.23	9.15	607,383	92.06	78.54	0.64	6.33	90,674	61,470	29,204
2018	42.27	9.15	607,383	96.77	82.61	0.67	6.63	95,298	64,223	31,074
2019	44.44	9.15	607,383	101.69	86.76	0.71	6.95	100,161	67,036	33,125
2020	46.70	9.15	607,383	106.88	91.29	0.74	7.28	105,266	70,092	35,174

* Does not include additional capacity credit for high capacity factor.

** Based on 96.3 percent capacity factor and 72 MW capacity.

EXHIBIT NO.___________

WITNESS: ROLLINS

DESCRIPTION: RESPONSE TO STAFF INTERROGATORY 18

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 23
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 18

18. Q. Please provide the projected reliability levels identified in Tables 1B.7.2-1, 1B.7.2-2, and 1B.7.2-3 for each year through 2008 based on the inclusion of the 330 MW of Stanton 2. Provide the same analysis based on the inclusion of 220 MW of Stanton 2 through the 1997-2009 term of the expected 110 MW UPS sale.

A. See the following tables for projected reliability levels.

Projected Reliability Levels Including 330 MW of Stanton 2
and Without Additional Demand-Side Management

Winter Season	Total Capacity MW	Peak Demands* MW	Reserve Margin percent	Year	EUE percent
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,077	30.1	1993	0.14
1993-94	1,401	1,111	26.1	1994	0.12
1994-95	1,401	1,144	22.5	1995	0.16
1995-96	1,401	1,177	19.0	1996	0.55
1996-97	1,731***	1,220	41.9	1997	0.23
1997-98	1,731	1,258	37.6	1998	0.15
1998-99	1,731	1,288	34.4	1999	0.09
1999-2000	1,731	1,319	31.2	2000	0.11
2000-01	1,731	1,354	27.8	2001	0.15
2001-02	1,731	1,341	29.1	2002	0.12
2002-03	1,731	1,358	27.5	2003	0.26
2003-04	1,731	1,332	30.0	2004	0.23
2004-05	1,731	1,342	29.0	2005	0.22
2005-06	1,731	1,343	29.0	2006	0.27
2006-07	1,731	1,353	27.9	2007	0.34
2007-08	1,731	1,391	24.4	2008	0.39

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 330 MW capacity addition of Stanton 2.

041191

Projected Reliability Levels Including 220 MW of Stanton 2 and Without Additional Demand-Side Management

Winter Season	Total Capacity MW	Peak Demands* MW	Reserve Margin percent	Year	EUE percent
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,077	30.1	1993	0.14
1993-94	1,401	1,111	26.1	1994	0.12
1994-95	1,401	1,144	22.5	1995	0.16
1995-96	1,401	1,177	19.0	1996	0.55
1996-97	1,621***	1,220	32.9	1997	0.30
1997-98	1,621	1,258	28.9	1998	0.17
1998-99	1,621	1,288	25.9	1999	0.14
1999-2000	1,621	1,319	22.9	2000	0.22
2000-01	1,621	1,354	19.7	2001	0.25
2001-02	1,621	1,341	20.9	2002	0.27
2002-03	1,621	1,358	19.4	2003	0.40
2003-04	1,621	1,332	21.7	2004	0.35
2004-05	1,621	1,342	20.8	2005	0.38
2005-06	1,621	1,343	20.7	2006	0.45
2006-07	1,621	1,353	19.8	2007	0.55
2007-08	1,621	1,391	16.5	2008	0.80
2008-09	1,621	1,425	13.8	2009	0.94

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 220 MW capacity addition of Stanton 2.

Projected Reliability Levels Including 330 MW of Stanton 2
and Additional Demand-Side Management

Winter Season	Total Capacity MW	Peak Demands* MW	Reserve Margin percent	Year	EUE percent
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,073	30.6	1993	0.14
1993-94	1,401	1,105	26.8	1994	0.12
1994-95	1,401	1,134	23.5	1995	0.15
1995-96	1,401	1,163	20.5	1996	0.53
1996-97	1,731***	1,202	44.0	1997	0.22
1997-98	1,731	1,237	39.9	1998	0.14
1998-99	1,731	1,269	36.4	1999	0.09
1999-2000	1,731	1,298	33.4	2000	0.10
2000-01	1,731	1,333	29.9	2001	0.16
2001-02	1,731	1,316	31.5	2002	0.08
2002-03	1,731	1,329	30.2	2003	0.23
2003-04	1,731	1,301	33.1	2004	0.19
2004-05	1,731	1,309	32.2	2005	0.18
2005-06	1,731	1,309	32.2	2006	0.22
2006-07	1,731	1,318	31.3	2007	0.28
2007-08	1,731	1,351	28.1	2008	0.29

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 330 MW capacity addition of Stanton 2.

041191

	MW	MW	percent		percent
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,073	30.6	1993	0.14
1993-94	1,401	1,105	26.8	1994	0.12
1994-95	1,401	1,134	23.5	1995	0.15
1995-96	1,401	1,163	20.5	1996	0.53
1996-97	1,621***	1,202	34.9	1997	0.29
1997-98	1,621	1,237	31.0	1998	0.16
1998-99	1,621	1,269	27.7	1999	0.13
1999-2000	1,621	1,298	24.9	2000	0.20
2000-01	1,621	1,333	21.6	2001	0.21
2001-02	1,621	1,316	23.2	2002	0.24
2002-03	1,621	1,329	22.0	2003	0.35
2003-04	1,621	1,301	24.6	2004	0.29
2004-05	1,621	1,309	23.8	2005	0.34
2005-06	1,621	1,309	23.8	2006	0.35
2006-07	1,621	1,318	23.0	2007	0.42
2007-08	1,621	1,351	20.0	2008	0.64
2008-09	1,621	1,382	17.3	2009	0.75

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 220 MW capacity addition of Stanton 2.

041191

Projected Reserve Margin Including 330 MW of Stanton 2
and Additional Demand-Side Management
Under Extreme Weather Conditions

Winter Season	Total Capacity MW	Extreme Peak Demands* MW	Reserve Margin percent
1990-91	1,197	1,101	8.7
1991-92	1,197	1,135	5.5
1992-93	1,401**	1,142	22.7
1993-94	1,401	1,178	18.9
1994-95	1,401	1,210	15.8
1995-96	1,401	1,241	15.7
1996-97	1,731***	1,282	35.0
1997-98	1,731	1,322	30.9
1998-99	1,731	1,357	27.6
1999-2000	1,731	1,387	24.8
2000-01	1,731	1,426	21.4
2001-02	1,731	1,410	22.8
2002-03	1,731	1,426	17.6
2003-04	1,731	1,398	23.8
2004-05	1,731	1,410	22.8
2005-06	1,731	1,412	22.6
2006-07	1,731	1,424	21.6
2007-08	1,731	1,457	18.8

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 330 MW capacity addition of Stanton 2.

041191

Projected Reserve Margin Including 220 MW of Stanton 2
and Additional Demand-Side Management
Under Extreme Weather Conditions

Winter Season	Total Capacity MW	Extreme Peak Demands* MW	Reserve Margin percent
1990-91	1,197	1,101	8.7
1991-92	1,197	1,135	5.5
1992-93	1,401**	1,142	22.7
1993-94	1,401	1,178	18.9
1994-95	1,401	1,210	15.8
1995-96	1,401	1,241	15.7
1996-97	1,621***	1,282	26.4
1997-98	1,621	1,322	22.6
1998-99	1,621	1,357	19.5
1999-2000	1,621	1,387	16.9
2000-01	1,621	1,426	13.7
2001-02	1,621	1,410	14.9
2002-03	1,621	1,426	13.7
2003-04	1,621	1,398	15.9
2004-05	1,621	1,410	15.0
2005-06	1,621	1,412	14.8
2006-07	1,621	1,424	13.8
2007-08	1,621	1,457	11.3
2008-09	1,621	1,490	8.8

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.
***Includes 220 MW capacity addition of Stanton 2.

041191

EXHIBIT NO.__________

WITNESS: ROLLINS

DESCRIPTION: HISTORICAL RELIABILITY LEVELS

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 24
COMPANY/ WITNESS: Rollins
DATE: 6/18/91

Table 1B.7.1-1
Historical Reliability Levels

Year	Total Capacity MW	Annual Peak* MW	Reserve Margin percent	Unit Addition	Capacity Addition MW	LOLP days/yr	EUE perc
1972	426	381	11.81			9.0	0.6
1973	418	406	2.96			14.9	1.0
1974	767	629	21.94	Ind. Riv. 3	347	9.4	0.6
1975	775	641	20.90			4.7	0.3
1976	776	660	17.58			5.0	0.3
1977	752	718	4.74	Cry. Riv. 3	13	1.5	0.1
1978	760	437	73.91			1.9	0.1
1979	758	496	52.82			3.7	0.1
1980	758	547	38.57			6.1	0.3
1981	743	582	27.66			7.0	0.3
1982	873	571	52.89	McIntosh 3	130	3.5	0.2
1983	833	584	42.64	St. Lucie 2	49	2.1	0.1
1984	817	564	44.86			3.1	0.1
1985	817	708	15.40			14.6	1.7
1986	817	749	9.08			10.0	0.7
1987	1,1[illegible]6	764	46.07	Stanton 1	299	4.6	0.3
1988	1,148	784	46.43			11.1	1.2
1989	1,194	950	25.68	Ind. Riv. A & B	46	2.2	0.1
	Average		30.89				

*Includes firm sales to other utilities.

Table 1B.7.2-1
Projected Reliability Levels Without
Additional Demand-Side Management

Winter Season	Total Capacity MW	Peak Demands* MW	Reserve Margin percent	Year	EUE percent	LOLP days/yr
1990-91	1,197	1,036	15.5	1991	0.65	3.2
1991-92	1,197	1,068	12.1	1992	1.68	2.3
1992-93	1,401**	1,077	30.1	1993	0.14	1.1
1993-94	1,401	1,111	26.1	1994	0.12	1.8
1994-95	1,401	1,144	22.5	1995	0.16	1.8
1995-96	1,401	1,177	19.0	1996	0.55	3.0
1996-97	1,401	1,220	14.8	1997	0.98	5.9
1997-98	1,401	1,258	11.4	1998	0.64	5.3

*Includes firm sales to other utilities.
**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.

a0eae

TABLE 1B.7.2-1A
PROJECTED RELIABILITY LEVELS WITHOUT
ADDITTIONAL DEMAND-SIDE MANAGEMENT

WINTER SEASON	EXISTING CAPACITY	PEAK DEMANDS*	RESERVE MARGIN	CAPACITY REQUIRED TO MEET 15 % RESERVE MARGIN	YEAR	ASSUMED CAPACITY ADDITTIONS TO REACH TARGET .5% EUE**	EUE
	MW	MW	percent	MW		MW	percent
1990 - 91	1197	1036	15.5	-5.60	1991		0.65
1991 - 92	1197	1068	12.1	31.20	1992		1.68
1992 - 93	1401	1077	30.1	-162.45	1993		0.14
1993 - 94	1401	1111	26.1	-123.35	1994		0.12
1994 - 95	1401	1144	22.5	-85.40	1995		0.16
1995 - 96	1401	1177	19.0	-47.45	1996	103	0.24
1996 - 97	1401	1220	14.8	2.00	1997	103	0.43
1997 - 98	1401	1258	11.4	45.70	1998	103	0.21
1998 - 99	1401	1294	8.3	87.10	1999	103	0.29
1999 - 00	1401	1326	5.7	123.90	2000	206	0.16
2000 - 01	1401	1362	2.9	165.30	2001	206	0.18
2001 - 02	1401	1350	3.8	151.50	2002	206	0.32
2002 - 03	1401	1368	2.4	172.20	2003	206	0.38
2003 - 04	1401	1343	4.3	143.45	2004	206	0.28
2004 - 05	1401	1354	3.5	156.10	2005	206	0.24

* INCLUDES FIRM SALES TO OTHER UTILITIES

** BASED ON INSTALLING OUC'S OWNERSHIP SHARE OF COMBUSTION TURBINES
EQUIVALENT TO THE INDIAN RIVER C & D COMBUSTION TURBINES

EXHIBIT NO.___________

WITNESS: ROLLINS

DESCRIPTION: RESPONSE TO STAFF INTERROGATORY 20

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EU EXHIBIT NO. 25
COMPANY/
WITNESS: Rollins
DATE: 6/18/91

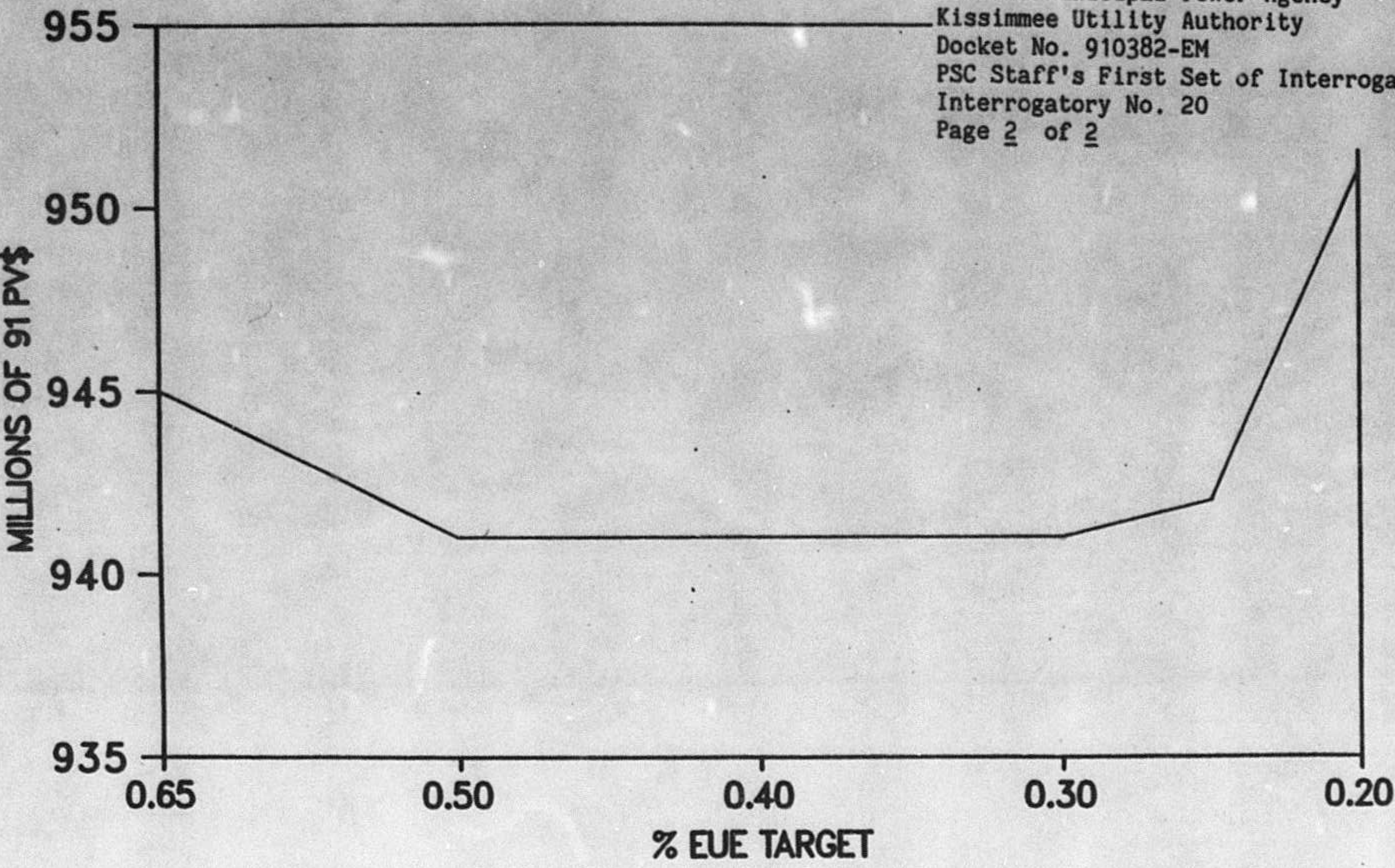


FIGURE 7-6
EXPECTED VALUE OF VARIOUS MAXIMUM % EUE TARGET LEVELS
WITH A MINIMUM 15% RESERVE TARGET

20. Q. Please provide the calculations and an explanation for the targeted Expected Unserved Energy (EUE) levels of 0.3 to 0.50 EUE for OUC's system.

A. As mentioned on page 1B.7.1-2 of Subsection 1B.7.1, the EUE criterion is based on the OUC Long-Range Power Supply and Demand-Side Planning Study completed by Southern Electric International (SEI) in May 1989. The objective of the study was to develop a reliability level that minimized cost to OUC customers. For your convenience, a copy of the figure which graphically illustrates the cost associated with various levels of EUE is attached. For a detailed explanation of the methodology used to generate the figure and the optimum EUE level, see Section 7.0 in the SEI study provided in Interrogatory No. 13.

Orlando Utilities Commission/Florida Municipal Power Agency/Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness: Myron R. Rollins
Late Filed Exhibit No. 26
Description: Summer and Winter Reserve Margin With and Without Stanton 2 for each Petitioner

ORLANDO UTILITIES COMMISSION
RESERVE MARGIN WITH AND WITHOUT STANTON UNIT 2

	WITHOUT STANTON 2		WITH STANTON 2	
YEAR*	WINTER RESERVE MARGIN	SUMMER RESERVE MARGIN	WINTER RESERVE MARGIN	SUMMER RESERVE MARGIN
1987	13	44		
1988	51	46		
1989	33	37		
1990	26	33		
1991	16	19		
1992	12	34		
1993	31	33		
1994	27	30		
1995	24	27		
1996	20	23		
1997	17	20	17	49
1998	13	16	40	44
1999	10	13	36	41
2000	8	11	33	38
2001	5	8	30	34
2002	6	8	32	34
2003	5	6	30	32
2004	8	9	33	35
2005	7	8	32	34
2006	7	8	32	34
2007	6	7	31	33

*October of previous year through September of current year.

KISSIMMEE UTILITY AUTHORITY RESERVE MARGIN WITH AND WITHOUT STANTON UNIT 2*

YEAR	WITHOUT STANTON 2 WINTER RESERVE MARGIN	WITHOUT STANTON 2 SUMMER RESERVE MARGIN	WITH STANTON 2 WINTER RESERVE MARGIN	WITH STANTON 2 SUMMER RESERVE MARGIN
1987	10	2		
1988	4	5		
1989	24	24		
1990	(21)	(1)		
1991	(7)	(1)		
1992	(7)	(1)		
1993	(34)	(31)		
1994	(20)	(16)		
1995	(24)	(21)		
1996	(28)	(25)		
1997	(31)	(28)	(25)	(21)
1998	(34)	(32)	(28)	(25)
1999	(37)	(35)	(31)	(29)
2000	(40)	(38)	(34)	(32)
2001	(42)	(41)	(37)	(36)
2002	(45)	(44)	(40)	(39)
2003	(53)	(53)	(48)	(47)
2004	(54)	(55)	(50)	(50)
2005	(56)	(56)	(51)	(52)
2006	(58)	(58)	(53)	(54)
2007	(59)	(60)	(55)	(55)

* Does not include Partial Requirements purchases.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness: Myron Rollins
Late Filed Exhibit No. 26
Description: Reserve Margin without Stanton Unit #2

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS WITHOUT STANTON UNIT #2 CAPACITY

FMPA PARTICIPANTS

Line No		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Participant Resources [1]......(MW)	897	904	965	948	947	968	954	954	937	925	923	921	895	888	909	904	872	829	806	769	746
2	Unit Power Sales [2]..........(MW)	0	0	0	0	(5)	(5)	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Participant Resources .....(MW)	897	904	965	948	942	963	949	949	937	925	923	921	895	888	909	904	872	829	806	769	746
4	Participant Peak Demand ....(MW)	758	793	918	838	912	943	975	1,005	1,036	1,063	1,088	1,114	1,140	1,167	1,191	1,217	1,242	1,265	1,292	1,315	1,344
5	Participant System Sales [3]..(MW)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	0	0
6	Net Participant Peak Demand ...(MW)	773	808	933	853	927	958	990	1,020	1,051	1,078	1,103	1,129	1,155	1,182	1,206	1,232	1,257	1,280	1,307	1,315	1,344
7	Excess/(Deficiency) ....(MW)	124	97	32	95	16	5	-41	-71	-114	-153	-180	-208	-260	-294	-297	-328	-385	-452	-501	-547	-598
8	Reserve Margin ....(%)	16%	12%	3%	11%	2%	1%	-4%	-7%	-11%	-14%	-16%	-18%	-23%	-25%	-25%	-27%	-31%	-35%	-38%	-42%	-45%

------
[1] Annual average installed capacity based on unit ratings reported in this filing and status of units at time of peak demand. Firm purchases excluding partial requirements purchases from FPL and FPC included as participant resources.
[2] Represents Unit Power Sales for the City of Homestead for the period 1991- 1994.
[3] Represents current System Sales by the City of Lake Worth through the year 2005.

Correction to Application
Table 1B.6.3-8
(p. 1B.6.3 - 29)

by Dr. Douglas Norland

Coal Storage:	Total Resource Cost Test NPV = (11.6) B/C = 0.0
	Utility Cost Test NPV = (3.9) B/C = 0.0
	Rate Payer Impact Measure NPV = (5.7)
Standby Generation:	Total Resource Cost Test NVP = 1.1 B/C = 2.65
	Utility Cost Test NPV = (3.8) B/C = 0.31
	Rate Payer Impact Measure NPV = (17.1)

EXHIBIT NO. 28

WITNESS: ERICKSON / Norland

DESCRIPTION: PETITION DSM EVALUATION

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO: 28
COMPANY/ WITNESS: Erickson / Norland
DATE: 6/18/91

Table 1B.. 3-7
Orlando Utilities Commission
Residential DSM Programs
Primary Benefit/Cost Test Results

Demand-Side Program	Total Resource Cost Test Net Present Value ($million)	Total Resource Cost Test Benefit/ Cost Ratio	Utility Cost Test Net Present Value ($Million)	Utility Cost Test Benefit/ Cost Ratio	Ratepayer Impact Measure Net Present Value ($Million)
Compact Fluorescent	3.7	2.25	5.5	5 59	(5.0)
DLC - Central A/C	(4.4)	0.05	(19.0)	0.01	(17.4)
DLC - Water Heater	(3.1)	0.50	(32.4)	0.09	(28.6)
DLC - Heat Pump/Resistance Heat	6.0	3.40	(3.7)	0.69	(4.0)
HE Manual-Defrost Refrigerator	(0.1)	0.06	(0.1)	0.04	(0.1)
HE Auto-Defrost Refrigerator	(0.4)	0.14	(0.6)	0.10	(0.7)
HE Electric Water Heater	(1.5)	0.38	(5.2)	0.15	(6.6)
WH - Water Heat Recovery & Wraps	(9.3)	0.30	(4.2)	0.48	(0.9)
Heat Pump Water Heater	(1.7)	0.55	0.0	1.65	(2.0)
Solar Water Heater	(2.6)	0.23	(0.6)	0.55	(1.6)
Replace Resistance Heat with/ Heat Pump	10.6	2.10	16.8	6.04	(6.0)
HE Central Heat Pump	(2.3)	0.28	(0.9)	0.49	(1.4)
HE Room Heat Pump	(1.1)	0.24	(0.4)	0.48	(0.5)
HE Freezers	(0.1)	0.06	(0.1)	0.05	(0.1)
HE Window A/C	(0.4)	0.07	(0.2)	0.14	(0.2)

Benefit-Cost Test	Benefits* [Less]	Costs*
Total Resource Cost	Fuel Savings Capacity Savings	Customer Costs Program Administration
Utility Cost	Fuel Savings Capacity Savings	Program Administration Rebates or Subsidies
Rate Impact Measures	Fuel Savings Capacity Savings	Program Administration Rebates or Subsidies Revenue Losses

* Present Value at the Test's Applicable Discount Rate.

Comparison of Society, Utility, and Nonparticipants Benefit-Cost Tests.

Three Regulatory Benefit-Cost Tests
Figure 1B.6.3-6

to $2,000. Given the above capacity impacts, this corresponds to a capacity cost that substantially exceeds the current cost.

Based upon this analysis, the solar water heater was dropped from further consideration.

1B.6.4.2.10 Curtailable Rates. Load reductions for OUC's curtailable rates for General Service Demand Primary and Secondary customers are estimated based on projections of standby generation to achieve curtailments. Costs associated with the curtailable rate program have not been developed since the curtailable rates are an existing program. Energy reductions have not been developed since curtailments are only rarely expected to be implemented and associated energy reductions would be minimal. Load reductions are shown in Table 1B.6.4-1.

1B.6.4.3 Results of Detailed Analyses

The summary results of the detailed analysis are given in Table 1B.6.4-2. Clearly, as shown in Table 1B.6.4-2, direct load control has the greatest impact on the system peak demand. The changes in production costs calculated in the RESHAPE model are small due to the limited amount of control exercised. Substantial reductions in winter and summer peaks are also observed for commercial lighting, conversion of residential resistance heating to heat pumps, and commercial thermal energy storage.

Based upon the above results, TOU rates and the residential lighting program were dropped from further consideration due to the small impact of these programs. The three-hour shutoff of electric space heating load control option was dropped in favor of the cycling strategy since cycling produces less customer inconvenience than the total shutoff. Finally, commercial thermal energy storage was dropped because of its failure to reduce OUC's winter peak. This of course assumes that OUC will remain a winter peaking utility. Thus, as the relative difference in the summer and winter peaks decreases, the thermal energy storage option should be reevaluated periodically.

The remaining DSM options were combined into two groups: (1) commercial lighting and conversion of residential resistance heating to heat pumps and (2) Group 1 plus direct load control of water heaters, space heating, and air conditioning. For both of these groups, load shape estimates were produced for the 1993 to 2020 planning horizon.

A program starting date of 1995 was assumed for direct load control programs. A three- to four-year time frame was felt necessary to conduct more detailed investigations, possibly involving pilot studies and to allow for an effective program initiation. For the commercial lighting program and the conversion of resistance to heat pumps, a shorter lead time seemed to be required. Thus, a starting date of 1993 was assumed.

Statistics of the two DSM cases and the base case are presented in Table 1B.6.4-3. Program costs as well as participation rates are given in Tables 1B.6.4-4 through 1B.6.4-6. All costs are given in nominal dollars. A general cost escalation rate of 4 percent per year was assumed. With the exception of the commercial lighting incentive, which escalates only by 1 percent a year, all other incentives follow the general escalation rate. The 1 percent escalation rate for commercial lighting was based upon the assumption that once the program gains momentum, the importance of incentives will decrease.

The modified load shape data as well as the costs are used with supply options to arrive at the integrated supply- and demand-side expansion plan as described in Subsection 1B.11.0.

Table 1B.6.4-1
Load Reductions for Curtailable Rates

Year	Winter Peak Demand Reduction kW
1991	0
1992	392
1993	1,204
1994	2,054
1995	2,945
1996	3,446
1997	4,411
1998	4,969
1999	6,013
2000	7,105
2001	7,760
2002	8,940
2003	10,172
2004	10,937
2005	12,266
2006	13,652
2007	13,980
2008	14,315
2009	14,659
2010	15,011
2011	15,371
2012	15,740
2013	16,118
2014	16,505
2015	16,901
2016	17,306
2017	17,722
2018	18,147
2019	18,582
2020	19,028

Table 1B.6.4-3
Annual Summary Statistics of Two DSM Cases and the B

Year	Annual Peak--Winter: Base Case (MW)	Annual Peak--Winter: Case 1 (MW)	Annual Peak--Winter: Case 2 (MW)	Annual Net Energy for Load: Base Case (GWh)	Annual Net Energy for Load: Case 1 (GWh)	Annual Net Energy for Load: Case 2 (GWh)	Bas Cas
1993	860	867	854	4102	4096	4096	54.
1994	894	890	880	4271	4257	4257	54.
1995	937	930	920	4473	4452	4452	54.
1996	980	969	960	4690	4662	4662	54.
1997	1023	1009	995	4891	4855	4855	54.
1998	1061	1045	1027	5083	5037	5037	54.
1999	1097	1078	1053	5263	5205	5205	54.
2000	1134	1113	1084	5444	5376	5376	54.
2001	1175	1154	1110	5672	5593	5593	55.
2002	1206	1181	1141	5865	5771	5771	55.
2003	1245	1216	1175	6092	5983	5983	55.
2004	1282	1251	1208	6288	6165	6165	55.
2005	1311	1278	1235	6469	6328	6328	56.
2006	1336	1302	1258	6628	6471	6471	56.
2007	1367	1332	1287	6821	6647	6647	56.
2008	1405	1365	1319	7030	6845	6845	57.
2009	1440	1397	1350	7219	7028	7028	57.
2010	1490	1447	1390	7401	7201	7201	57.
2011	1535	1487	1430	7714	7504	7504	57.
2012	1574	1527	1475	7940	7734	7734	57.
2013	1622	1569	1516	8191	7966	7966	57.
2014	1664	1611	1558	8440	8208	8208	57.
2015	1712	1655	1599	8699	8457	8457	58.
2016	1765	1698	1640	8962	8713	8713	58.
2017	1806	1743	1684	9239	8977	8977	58.
2018	1855	1792	1731	9519	9249	9249	58.
2019	1912	1843	1780	9810	9529	9529	58.
2020	1960	1896	1826	10107	9818	9818	58.

Case 1: Commercial Lighting and Conversion of Resistance Heat to Heat Pumps

Case 2: Direct Load Control (Water Heaters, Heating and Cooling) with Case 1 in place

Table 1B.6.4-6
Costs and Participation for Direct Load Control Program

Year	Cumulative Fixed Program Cost ($1,000)	Water Heating	A/C	Heating	Cumulative Variable Program Costs ($1,000)	Cumulative Program Incentives ($1,000)	Cu To ($
1994	200						
1995	454	2373	1883	1777	518	299	[illegible]
1996	719	4918	3949	3712	1096	948	[illegible]
1997	994	7502	6189	5786	1734	1993	[illegible]
1998	1200	10401	8591	8806	2433	3494	[illegible]
[illegible]	1577	[illegible]	[illegible]	[illegible]	3192	5585	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2010	5758	46509	44015	39605	[illegible]	78973	
2011	6226	47132	44622	40561	14709	91116	
2012	6226	47765	45238	41452	15001	103946	
2013	6226	48405	45862	42360	15309	117500	
2014	6226	49053	46493	43283	15635	131828	
2015	6226	49711	47136	44225	15981	146949	
2016	6226	50378	47786	45183	16348	162932	
2017	6226	51052	48444	46160	16735	179818	
2018	6226	51737	49114	47107	17146	197652	
2019	6226	52431	49792	48171	17582	216500	
2020	6226	53133	50476	49201	18042	236410	

Compact Fluorescent Lighting	16.19	.2
Ellipsoidal Reflector Floodlamps	9.95	1.6
Ventilation Tune-Up	2.38	.0
Window Film	1.70	.0
Demand Management Co-ops	.61	3.5
HE A/C Package System	.58	.0
De-Lamping with Reflectors	.55	1.9
Heat Pump Water Heater	.53	.0
Walk-Through Audit	.45	.0
Water Heat Heat Recovery System	.41	.0
HP Sodium & Metal Halide Lighting	.34	.0
Stand-By Generation	.31	4.4
In-Depth Audit	.29	.1
HE Motors	.29	.0
T8 Lamps & Electronic Ballasts	.21	.4
HE Lamps & Electronic Ballasts	.16	.7
HE Conventional Heat Pump	.13	.7
HE Water Heater	.05	.0
ASD - Ventilation Motors	.03	.0
EMS - Ventilation	.03	.9
Economizer	.00	.0
Cool Storage	.00	.0

17. Q. Please provide a cost benefit analysis which incorporates the combination of direct load control of the customers heating and air conditioning system, electric water heater and electric pool pump.

A. Direct load control of pool pump was not evaluated by Battelle. Insufficient data on pool pump stock and operating characteristics prevented the estimation of load shape impacts. In addition, OUC sets pool pump timers so that the pump operates only during off-peak hours as part of the existing Residential Energy Survey Program. Pool pumps set to pump only during off-peak hours would not be affected by direct load control. Because it is an existing program, the savings associated with the program are implicitly accounted for in the base load forecast.

Table 1B.6.1-9

Cummulative Impact of All Energy Conservation Programs
Estimated for Years 1982-1999
Existing FEECA Programs

YEAR	CUMMULATIVE AVOIDED CAPACITY	CUMMULATIVE AVOIDED ENERGY
	MW	GHh
1982	1.3	5.4
1983	2.2	9.2
1984	3.4	13.6
1985	4.5	17.7
1986	6.0	22.6
1987	8.0	33.5
1988	10.2	45.0
1989	11.9	54.8
1990	12.7	58.1
1991	13.8	63.1
1992	15.1	68.4
1993	16.7	74.8
1994	18.4	81.5
1995	20.4	89.3
1996	22.5	97.3
1997	24.9	106.0
1998	27.0	114.3
1999	29.0	122.5

3. Q. Please provide further detail on the conservation offerings of OUC during the 1980's. Include the year(s) each conservation program was offered; its ending date as appropriate; and its estimated cumulative MW savings through December 31, 1989 using the methodology incorporated in the Planning Hearing Docket as reported to the FCG.

A. The details requested appear on the attached spreadsheet.

Orlando Utilities Commissio
Florida Municipal Power Agen.,
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 3

Program	First Year Offered By OUC	Year Approved by FPSC	Year Program Ended	Estimated Cumulative Savings in Peak Demand Demand thru 12/31/89 Summer-MW	Winter-MW
Residential Conservation Service (RCS) Class "A" Computerized Audits	1981	1981	C (Upon Request)	1.51	1.34
Free Home Energy Surveys (FHS)	1973	1981	C	3.76	3.04
Pool Pump Trippers	1984	1983	C (As part of FHS)	1.18	0.34
Small Commercial Audits	1973	1981	C	1.53	0.42
Energy Efficient Appliances	1984	1981	1990 (1)	0.13	0.06
Efficient Street Lighting	1981	1981	C	0	0
Heat Pump and High Efficiency Air Conditioning	1984	1981	C	2.74	2.71
Residential Ceiling Reinsulation	1981	1981	1990 (2)	0.78	0.78
Technical Energy Survey	1987	1987	1990	0.32	0.26
Abbreviated Basic Commercial (ABC) Survey	1987	1987	1990 (2)	1.54	1.36
New Customer Advisory Service	1987	1987	1990	0.01	0.01
Weatherization Measures and Practices	1981	1981	1990 (2)	NQ	NQ
High User Awareness	1981	1981	1990 (2)	NQ	NQ
Energy Education and School Outreach	1981	1981	C	NQ	NQ
Low Income Home Energy Fix-up	1985	1990	C	-	-

C = Continuing NQ = Non-Quantifiable

(1) = Superseded by National Appliance Efficiency Standards, 1987.

(2) = Continuing Under a New Program

041191

EXHIBIT NO. 33

WITNESS: ERICKSON

DESCRIPTION: RESPONSE TO STAFF INTERROGATORY 10

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 33
COMPANY/ WITNESS: Erickson
DATE: 6/18/91

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 10

10. Q. What amounts of winter and summer demand reductions did OUC report to the FCG in Docket 890004-EU (1989 Planning Hearing Forecast Document) which are associated with OUC's conservation program?

A. These amounts are found on the attached Table No. 4 which appeared in the 1989 Planning Hearing Forecast Document on page 165.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
PSC Staff's First Set of Interrogatories
Interrogatory No. 10

TABLE 4

ORLANDO UTILITIES COMMISSION

CONSERVATION, LOAD MANAGEMENT AND QUALIFYING FACILITIES IMPACT ON DEMAND AND ENERGY

1989 ANNUAL PLANNING HEARING

	WINTER IMPACTS					SUMMER IMPACTS					ENERGY IMPACTS			
YEAR	CONS	LM	QF'S	TOTAL	YEAR	CONS	LM	QF'S	TOTAL	YEAR	CONS	LM	QF'S	TOTAL
1987 /88	11	0	0	11	1988	10	0	0	10	1988	50	0	0	50
1988 /89	16	0	0	16	1989	14	0	0	14	1989	67	0	0	67
1989 /90	20	0	0	20	1990	17	0	0	17	1990	83	0	0	83
1990 /91	23	0	0	23	1991	22	0	0	22	1991	103	0	0	103
1991 /92	27	0	0	27	1992	24	0	0	24	1992	121	0	0	121
1992 /93	32	0	0	32	1993	30	0	0	30	1993	141	0	0	141
1993 /94	35	0	0	35	1994	32	0	0	32	1994	158	0	0	158
1994 /95	41	0	0	41	1995	38	0	0	38	1995	179	0	0	179
1995 /96	44	0	0	44	1996	40	0	0	40	1996	193	0	0	193
1996 /97	47	0	0	47	1997	43	0	0	43	1997	207	0	0	207
1997 /98	49	0	0	49	1998	46	0	0	46	1998	221	0	0	221
1998 /99	54	0	0	54	1999	49	0	0	49	1999	237	0	0	237
1999 / 0	56	0	0	56	2000	52	0	0	52	2000	252	0	0	252
2000 / 1	59	0	0	59	2001	55	0	0	55	2001	266	0	0	266
2001 / 2	62	0	0	62	2002	57	0	0	57	2002	274	0	0	274
2002 / 3	63	0	0	63	2003	59	0	0	59	2003	287	0	0	287
2003 / 4	67	0	0	67	2004	61	0	0	61	2004	296	0	0	296
2004 / 5	69	0	0	69	2005	65	0	0	65	2005	308	0	0	308
2005 / 6	70	0	0	70	2006	65	0	0	65	2006	315	0	0	315
2006 / 7	72	0	0	72	2007	66	0	0	66	2007	322	0	0	322

EXHIBIT NO. 34

WITNESS: ERICKSON

DESCRIPTION: OUC'S 1982 CONSERVATION PROGRAM FILING

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 34
COMPANY/
WITNESS: Erickson
DATE: 6/18/91

Docket No. 910382-EM
Additional Data Request-OUC's 1982 Conservation Program Filing and OUC's 1991 Conservation Program Filing

A DESCRIPTION OF
ORLANDO UTILITIES COMMISSION
EXISTING AND PROPOSED ENERGY CONSERVATION
PROGRAMS AND ACTIVITIES
AS REQUIRED UNDER THE
FLORIDA ENERGY EFFICIENCY AND CONSERVATION ACT

* * * * * *

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET 800689-EG (MC)

ORDER NUMBER 9680-RESUBMITTAL

JANUARY 30, 1981

TALLAHASSEE, FLORIDA

SYSTEM PLANNING DIVISION

CONSERVATION DIVISION

* TABLE OF CONTENTS *

* * *

I. POSITION STATEMENT

Summary of OUC Response to PSC Order No. 9680

This resubmittal document contains a reiteration of Orlando Utilities Commission (OUC) existing conservation programs as submitted November 1, 1980 under Docket Number 800522-EG. This document also contains the descriptions of OUC's proposed conservation programs as required under the Florida Energy Efficiency and Conservation Act (FEECA).

This resubmittal is based on an OUC interim demand and energy forecast. OUC's base forecast and conservation program peak and energy reductions are currently being developed by consultants. The forecast will not be available for several weeks. We have submitted the conservation goals forecast based on an evaluation of the more recent historical peaks, annual energy and customer growth rates. The base forecast submitted was then derived by adding back the conservation impacts enumerated in this report. This document will be resubmitted for your approval as soon as the consultants have developed the official base forecast and reviewed and confirmed the impact of the proposed conservation programs.

The Orlando Utilities appreciates the Public Service Commission's (PSC) consideration of the November 1, 1980 submittal and recognized the severe time constraints all parties were working against. The disapproval of the OUC programs were in part caused by these time constrictions and internal staff limitations. OUC does appreciate the PSC staff commendations relating to the existing conservation programs as described in the November 1, 1980 submittal. In reviewing the program submittals of twelve of the smaller municipally owned systems, it was noticed with interest that they plan to adopt all or part of several OUC existing conservation programs.

Several unique factors will directly and indirectly contribute to OUC's system load growth during the next ten years. These factors include plant relocations, business expansions, hugh construction projects, socio-economic population stresses and the expected continued addition of all electric residential customers that will add demand and energy requirements well above existing residential average consumptive figures.

Listed below are some of the construction projects and factors which will influence and contribute to OUC's system load growth:

(1) Walt Disney World's Experimental Prototype Community of Tomorrow (EPCOT) construction.
(2) Western Electric's plant construction with 3,000 anticipated employees.
(3) Orlando International Jetport construction.
(4) Orange County Civic Convention Center breaking ground.
(5) Westinghouse and the University of Central Florida's plans for a computer research and technology center and Westinghouse's relocation of their turbine engineering division.
(6) Naval Training Center expansions.
(7) Martin Company plant expansions.
(8) Burrough's Corporation plant relocation and construction.
(9) Relocation of several national companies utilizing Orlando as regional and distribution headquarters.
(10) Additional tourist attractions to Central Florida planned.
(11) Retired military and northern influx of retirees.
(12) Miami-South Florida "exodus" moving to establish homes and businesses in Orlando and surrounding area.
(13) More than 160 million dollars currently committed to construction projects for downtown Orlando in 1981.

Orlando Utilities will utilize proven techniques to target conservation programs at all residential, commercial, and industrial energy conservation opportunities.

The listed conservation programs are expected to achieve the goals as set forth in Order Number 9552 with the anticipated projection of meeting the standards as mandated in the permanent rules. These conservation programs will be successful only if they receive acceptance within the market place, adequate market penetration and the acceptance of all classes of customers to adopt necessary conservation measures and practices. Adoption of proposed programs are contingent upon final approval by the Orlando Utilities Commission.

The accomplishment of OUC's conservation programs can be monitored to the extent that they are related to direct customer conservation participation. Monitoring of energy conservation activities relating to media advertising or public awareness programs are understandably difficult to statistically track.

Programs will be monitored to determine their degree of customer acceptance and market penetration. Programs may be modified or eliminated as a result of this activity and new cost effective programs may be introduced or others combined as needed to achieve maximum results.

OUC suggests that since the requirements for a utility to supply quarterly program schedules and reports was absent from the Emergency Rule and the Permanent Rules that the requirement specify annual reports.

Orlando Utilities Commission existing and proposed conservation programs will meet the goals as set forth in Order Number 9552 and Order Number 9680.

The results of the programs can be monitored.

OUC will implement those programs which will prove most cost effective to produce customer acceptance and market penetration.

OUC reserves the management prerogative to design and administer program content and program implementation.

The Orlando Utilities Commission remains open to adopt any proven and cost effective conservation programs suggested by the Public Service Commission. OUC welcomes the opportunity to increase efforts at energy conservation and will attempt to the best of its ability to continue to give maximum service to all OUC customers.

Orlando Utilities presents this resubmittal of conservation programs in the true spirit of a public utility that wants conservation to work and has labored for that purpose with all customers for years.

Orlando Utilities Commission
Interim Forecast
Before Effects of Conservation Programs

Year	Summer Peak Demand Integrated Net-MW	Net Energy For Load-GWH	Year	Winter Peak Demand Integrated Net-MW
1981	500	2395	--	--
1982	521	2481	1981-82	526
1983	543	2568	1982-83	544
1984	566	2655	1983-84	565
1985	586	2730	1984-85	583
1986	604	2802	1985-86	601
1987	621	2870	1986-87	616
1988	637	2933	1987-88	632
1989	653	2993	1988-89	646

* * * * * *

A SUMMARY OF

ORLANDO UTILITIES COMMISSION

CONSERVATION PROGRAMS RESULTS - 1989

	Programs	Demand Reduction - MW Winter	Summer	Energy Reduction GWH
1.	Residential Conservation Service (RCS) Audit	5.0	3.7	16.2
2.	Free Homeowner Advisory Surveys (alternate audit)	1.4	1.2	4.1
3.	Residential Heat Pump Replacement and	18.1	-	20.8
	High Efficiency Air Conditioner Replacement	--	27.2	38.4
4.	Energy Efficient Water Heating (water heater jacket)	1.4	1.6	15.2
-	waste heat recovery (new construction)	--	1.8	7.0
-	heat pump water heater (new construction)	0.5	0.2	2.4
-	heat pump water heater (based on audits)	2.5	1.0	11.7
-	waste heat recovery (based on audits)	--	1.4	5.6
-	waste heat recovery (based on a/c promotion)	--	.5	1.9
-	heat pump water heaters (based on a/c promotion)	.4	.2	2.0
5.	Energy Saver Award (new construction)	16.8	17.5	44.1
6.	Small Commercial Audit	0.4	1.0	12.1
7.	Large Commercial/Industrial Energy Management	0.1	9.6	19.2
8.	Efficient Appliances	11.2	12.8	53.6
9.	Street Light Conversion	1.4	-	5.8
10.	Pool Pump	3.8	4.0	2.1
11.	Weatherization Measures and Practices	4.0	4.5	16.7
12.	Solar Water Heater	--	0.6	5.0
	OUC TOTAL AT SALES LEVEL	67.1	88.8	283.9
	OUC TOTAL AT NET LEVEL (1.052)	71.0	93.0	299.0
	FEECA GOAL	71.0	93.0	299.0

CONSERVATION PROGRAMS

TIMETABLE OF START-UPS

Residential Conservation Service (RCS) Audits	1981
*Free Homeowner Advisory Surveys (alternate audit)	1973
Residential Heat Pump and High Efficiency Air Conditioning Replacement	1982
Energy Efficient Water Heating (existing residential market)	1982
Energy Efficient Water Heating (new construction)	1983
Efficient Appliance Promotion	1982
Street Light Conversion	1981
Small Commercial Audit	1982
Residential Pool Pump	1982
Solar Water Heater	1981
Weatherization Measures and Practices	1981
Large Commercial/Industrial Energy Management	1982
Energy Saver Home Award	1983
Customer Financial and Dealer Assistance	1982
High User Awareness	1982
Energy Education and Conservation School Outreach	1981
*Existing Programs (Section Two)	1973

*To Present

EXHIBIT NO. 35

WITNESS: ERICKSON

DESCRIPTION: OUC'S 1991 CONSERVATION PROGRAM FILING

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EU EXHIBIT NO. 35
COMPANY/
WITNESS: Erickson
DATE: 6/18/91

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

February 12, 1990

Mr. Steve Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
Tallahassee, FL 32399-0850

RE: Implementation Section
366.80-.85, Florida Statutes
Conservation Activities of Electric
and Natural Gas Utilities

Dear Mr. Tribble:

Please find enclosed one original and fifteen (15) copies of the new conservation programs of the Orlando Utilities Commission.

This submittal is required under Docket No. 89073-PU, Order No. 22176, Issued 11-14-89, and the Florida Energy Efficiency Conservation Act (FEECA).

Should you need further information, please call me at (407) 423-9101.

Sincerely,

Donald F. Meyers

Donald F. Meyers
Director of Conservation

DFM:sc
Enclosures
Routed: T. C. Pope
W. H. Herrington
A. R. Boyd
M. E. Mazak
D. E. Moore
G. M. Standridge
T. B. Tart
T. L. Smith
G. F. Erickson
D. F. Meyers
G. F. Carver

Table of Contents

A DESCRIPTION OF

ORLANDO UTILITIES COMMISSION

NEW ENERGY CONSERVATION PROGRAMS

AS REQUIRED UNDER THE

FLORIDA ENERGY EFFICIENCY AND CONSERVATION ACT

****

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 890737-PU

ORDER NO. 22176

ISSUED: 11-14-89

FEBRUARY 12, 1990

ENERGY SERVICES DIVISION
SYSTEM PLANNING DIVISION
CONSERVATION DIVISION

CUMULATIVE IMPACT OF CONSERVATION AND LOAD MANAGEMENT

YEAR	(1) SUMMER PEAK REDUCTION (MW)	(2) LOAD MGT SUMMER (MW)	(3) WINTER PEAK REDUCTION (MW)	(4) LOAD MGT WINTER (MW)	(5) NEL (GWH)	(6) AVOIDED CAPACITY (MW)	(7) REQUIRED GEN ADD (MW)
1982	1.6	0.0	0.9	0.0	5.4	1.3	
1983	3.0	0.0	1.3	0.0	9.2	2.2	
1984	4.3	0.0	2.5	0.0	13.6	3.4	
1985	5.4	0.0	3.6	0.0	17.7	4.5	
1986	7.2	0.0	4.8	0.0	22.6	6.0	
1987	9.4	0.0	6.5	0.0	33.5	8.0	
1988	11.8	0.0	8.6	0.0	45.0	10.2	
1989	13.5	0.0	10.6	0.0	54.8	11.9	39
1990	14.4	0.0	11.5	0.0	59.2	13.0	
1991	15.9	0.0	13.0	0.0	65.3	14.4	
1992	17.5	0.0	14.5	0.0	71.8	16.0	
1993	19.5	0.0	16.4	0.0	79.5	18.0	
1994	21.6	0.0	18.5	0.0	86.7	20.1	
1995	24.1	0.0	21.0	0.0	96.0	22.5	
1996	26.8	0.0	23.6	0.0	105.6	25.2	
1997	29.7	0.0	26.4	0.0	115.9	28.1	
1998	32.4	0.0	29.0	0.0	125.7	30.7	
1999	35.0	0.0	31.6	0.0	135.4	33.3	

(1) REDUCED OUC's OWNERSHIP SHARE OF INDIAN RIVER PLANT COMBUSTION TURBIN A AND B (76 MW) FROM 100% TO 48.8%. THESE UNITS WENT INTO SERVICE IN THE SUMMER OF 1989.

COGENERATION PLAN

Orlando Utilities Commission (OUC) has, since 1978, responded to over 22 requests for information about its avoided costs. These requests have come from a variety of sources such as government agencies, hospitals, industry, hotels, consultants, colleges and private citizens. The only cogeneration project in OUC's area, at the present time, is at the City of Orlando's McLeod Road Wastewater Treatment Facility. This is a self-service generation project consisting of 6-450 KW gas engines that can burn either natural gas or methane. No sales of power to OUC are contemplated as the load exceeds the generators' capability.

OUC is developing a cogeneration tariff package which consists of standard rates and standard offer contracts for as-available and firm purchases, transmission service rates, and a parallel operation agreement.

OUC has been cooperating with Orange County in a study of the feasibility of the County building a waste-to-energy plant. OUC will include the output of this facility as a alternative source, when it studies the need for its next base load generating unit addition.

OUC will continue to respond to all inquiries for information regarding its avoided cost.

EXHIBIT NO. 36

WITNESS: ERICKSON

DESCRIPTION: SUMMARY OF NON-FIRM LOAD TARIFFS

STAFF: SHINE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 36
COMPANY/ WITNESS: Erickson
DATE: 6/18/91

Docket No. 910382-EM
Data Request-Summary OP
Non-Firm Load Tariffs

DATA REQUEST - SUMMARY OF NON-FIRM LOAD TARIFFS

INDEX

RATE SCHEDULES

GSD - SEC - C
Revenue Code
808 Thru 811

GENERAL SERVICE - DEMAND SECONDARY

CURTAILABLE RATE SCHEDULE

GSD - SEC - C

Availability: To any customer, within OUC service area, where the measured monthly KW demand is 500 KW or more for twelve consecutive months ending with the current billing period and the customer agrees to curtail 200 KW or more of electric use upon request of OUC.

Conditions: Electric service, at a minimum, is curtailable during any time period that electric power and energy from OUC's available generation, transmission and distribution resources are required to maintain service to OUC's firm power customers. Curtailment times are set forth in special provision No. 3 of this Rate Schedule. OUC will not make off system purchases during curtailment periods to maintain service to curtailable loads.

Conditions of service are more fully defined under Special Provisions of this Rate Schedule.

Monthly Rate:

Customer Charge	$125.00
Demand Charge at	$ 7.00 per KW
Energy Charge at	5.604¢ per KWH

Curtailable Demand Credit at $ 1.50 per KW

Minimum Bill: Customer charge plus a demand charge of not less than 25 KW at the above demand rate per KW plus the charge for energy used less the curtailable demand credit if any.

Billing Demand: The maximum 15-minute KW demand measured during the billing period.

Curtailable Demand Credit The curtailable demand credit shall apply to the difference, if any, between the current billing demand and the contracted non-curtailable demand determined in accordance with special provision No. 2 of this rate.

CONTINUED ON SHEET NO. 5.051

CONTINUED FROM SHEET NO. 5.050

Fuel Cost: The monthly rate per KWH will be increased or decreased to reflect changes in the estimated fuel cost of delivered energy and subsequently adjusted for actual fuel cost of delivered energy above or below a base cost of 3.468¢ per KWH.

Municipal Tax and Outside City Charge: The monthly rate charges plus all adjustments are subject to the Municipal Utility Tax within the City of Orlando and to an equivalent charge outside the city. The Municipal Utility Tax and the outside-city charge do not apply to amounts for fuel above a cost of 0.638¢ per KWH.

Special Provisions:

1. As used in this Rate Schedule the term "Period of Requested Curtailment" shall mean a period for which OUC has requested curtailment.

2. Under the provisions of this rate, OUC will require a Curtailable Service Agreement with the Customers. The initial Non-Curtailable Demand shall be specified in the Agreement and shall be based on specifications for power requirements supplied to OUC by the Customer. If, after commencement of service, the Customer establishes a higher demand during any period of requested curtailment, the higher demand will automatically supersede and replace the prior Non-Curtailable Demand in future billing periods. In addition, the customer will be subject to billing for the higher demand in accordance with Special Provision No. 5 of this rate. If, after commencement of service, a lower demand is established during a period of requested curtailment, the Non-Curtailable Demand will be reduced to the lower level in future billing periods upon request of the Customer.

3. As an essential requirement for receiving the Curtailable Demand Credit provided under this Rate Schedule, a Customer shall be strictly responsible for the curtailment of his power requirements to no more than his Non-Curtailable Demand upon each request of OUC. Such requests will normally be made during periods of generation, transmission, or distribution capacity

CONTINUED ON SHEET NO. 5.052

CONTINUED FROM SHEET NO. 5.051

shortages on the OUC's system. OUC shall also have the right to request one additional curtailment each calendar year irrespective of capacity availability or operating conditions.

4. A Customer will be deemed to have complied with his curtailment responsibility if the maximum 15-minute KW demand established during each period of requested curtailment does not exceed his Non-Curtailable Demand and he has reached that level within 15 minutes of receiving the request.

5. If the maximum 15-minute KW demand established during any period of requested curtailment exceeds the Customer's Non-Curtailable Demand, the Customer will be billed for 125% of the Curtailable Demand Credit attributable to the amount of such excess demand in each billing period from the current month to the most recent prior billing period in which curtailment was requested, not to exceed a total of twelve billing periods.

6. Customers taking service under this curtailable rate schedule who desire to transfer to a firm rate schedule will be required to give OUC written notice at least sixty months prior to such transfer. Such notice shall be irrevocable.

GSD - PRI - C
Revenue Code
814 Thru 817

GENERAL SERVICE - DEMAND PRIMARY

CURTAILABLE RATE SCHEDULE

GSD - PRI - C

Availability: To any customer, within OUC service area, where the measured monthly KW demand is 500 KW or more for twelve consecutive months ending with the current billing period and the customer agrees to curtail 200 KW or more of electric use upon request of OUC. In addition the customer owns and maintains all equipment, except metering equipment, necessary to take service at 12,470 volts or higher and the service is metered at primary voltage.

Conditions: Electric service, at a minimum, is curtailable during any time period that electric power and energy from OUC's available generation, transmission and distribution resources are required to maintain service to OUC's firm power customers. Curtailment times are set forth in special provision No. 3 of this Rate Schedule. OUC will not make off system purchases during curtailment periods to maintain service to curtailable loads.

Conditions of service are more fully defined under Special Provisions of this Rate Schedule.

Monthly Rate:

Customer Charge	\$125.00
Demand Charge at	\$ 6.30 per KW
Energy Charge at	5.366¢ per KWH

Curtailable Demand Credit at \$ 1.50 per KW

Minimum Bill: Customer charge plus a demand charge of not less than 25 KW at the above demand rate per KW plus the charge for energy used less the curtailable demand credit if any.

Billing Demand: The maximum 15-minute KW demand measured during the billing period.

CONTINUED ON SHEET NO. 5.056

CONTINUED FROM SHEET NO. 5.055

Curtailable <u>Demand Credit</u> The curtailable demand credit shall apply to the difference, if any, between the current billing demand and the contracted non-curtailable demand determined in accordance with special provision No. 2 of this rate.

<u>Fuel Cost</u>: The monthly rate per KWH will be increased or decreased to reflect changes in the estimated fuel cost of delivered energy and subsequently adjusted for actual fuel cost of delivered energy above or below a base cost of 3.468¢ per KWH.

Municipal Tax and Outside <u>City Charge</u>: The monthly rate charges plus all adjustments are subject to the Municipal Utility Tax within the City of Orlando and to an equivalent charge outside the city. The Municipal Utility Tax and the outside-city charge do not apply to amounts for fuel above a cost of 0.638¢ per KWH.

Special <u>Provisions</u>:

1. As used in this Rate Schedule the term "Period of Requested Curtailment" shall mean a period for which OUC has requested curtailment.

2. Under the provisions of this rate, OUC will require a Curtailable Service Agreement with the Customers. The initial Non-Curtailable Demand shall be specified in the Agreement and shall be based on specifications for power requirements supplied to OUC by the Customer. If, after commencement of service, the Customer establishes a higher demand during any period of requested curtailment, the higher demand will automatically supersede and replace the prior Non-Curtailable Demand in future billing periods. In addition, the customer will be subject to billing for the higher demand in accordance with Special Provision No. 5 of this rate. If, after commencement of service, a lower demand is established during a period of requested curtailment, the Non-Curtailable Demand will be reduced to the lower level in future billing periods upon request of the Customer.

CONTINUED ON SHEET NO. 5.057

CONTINUED FROM SHEET NO. 5.056

3. As an essential requirement for receiving the Curtailable Demand Credit provided under this Rate Schedule, a Customer shall be strictly responsible for the curtailment of his power requirements to no more than his Non-Curtailable Demand upon each request of OUC. Such requests will normally be made during periods of generation, transmission, or distribution capacity shortages on the OUC's system. OUC shall also have the right to request one additional curtailment each calendar year irrespective of capacity availability or operating conditions.

4. A Customer will be deemed to have complied with his curtailment responsibility if the maximum 15-minute KW demand established during each period of requested curtailment does not exceed his Non-Curtailable Demand and he has reached that level within 15 minutes of receiving the request.

5. If the maximum 15-minute KW demand established during any period of requested curtailment exceeds the Customer's Non-Curtailable Demand, the Customer will be billed for 125% of the Curtailable Demand Credit attributable to the amount of such excess demand in each billing period from the current month to the most recent prior billing period in which curtailment was requested, not to exceed a total of twelve billing periods.

6. Customers taking service under this curtailable rate schedule who desire to transfer to a firm rate schedule will be required to give OUC written notice at least sixty months prior to such transfer. Such notice shall be irrevocable.

ORLANDO UTILITIES COMMISSION
FLORIDA MUNICIPAL POWER AGENCY
KISSIMMEE UTILITY AUTHORITY

DOCKET NO. 910382 - EM

WITNESS: Gerald F. Erickson

Late Filed Exhibit No. 37

Description: Detailed Summary of Conservation Program Savings through 12/31/89.

See attached spreadsheet.

BACKUP FOR 1989 CUMULATIVE IMPACT OF CONSERVATION PROGRAMS SINCE 1981
LATE FILED EXHIBIT 37

ORLANDO ULITILIES COMMISSION
FLA MUN POWER AGENCY
KISSIMMEE UTILITY AUTHORITY
DOCKET NO. 910382-EM

ENERGY GWH

PROGRAM	1981	1982	1983	1984	1985	1986	1987	1988	1989	CUST TOT	GEN TOT
RCS	0.54	0.73	0.78	2.27	0.69	0.35	0.12	0.00	0.00	5.48	5.77
FHS	1.20	1.60	1.71	0.62	1.30	1.09	1.10	1.84	1.65	12.11	12.75
CES	0.09	0.09	0.04	0.03	0.16	1.24	0.67	0.67	0.22	3.21	3.38
ST LT	0.15	0.28	0.48	0.36	0.52	0.28	0.30	0.12	0.15	2.64	2.78
HP/CAC	0.21	0.24	0.63	0.52	0.74	1.04	1.75	1.63	1.00	7.76	8.17
REFRIG				0.02	0.03	0.03	0.08	0.12	0.12	0.40	0.42
RAC						0.001	0.05	0.01	0.01	0.07	0.07
P. PUMP				0.35	0.23	0.33	0.17	0.12	0.08	1.28	1.35
CEIL INSL					0.18	0.28	0.26	0.31	0.20	1.23	1.29
TES							1.44	0.36	1.09	2.89	3.04
ABC							4.48	5.72	4.74	14.94	15.73
NCAS							0.00	0.00	0.08	0.08	0.08
CUST LEVEL	2.19	2.94	3.64	4.17	3.85	4.64	10.42	10.90	9.34	52.09	54.83
CUM	2.19	5.13	8.77	12.94	16.79	21.43	31.85	42.75	52.09		
METR LEVEL											

SUMMER PEAK MW

PROGRAM	1981	1982	1983	1984	1985	1986	1987	1988	1989	CUST TOT	GEN TOT
RCS	0.16	0.21	0.17	0.59	0.18	0.09	0.03	0.00	0.00	1.43	1.51
FHS	0.34	0.46	0.80	0.16	0.34	0.28	0.28	0.48	0.43	3.57	3.76
CES	0.03	0.03	0.02	0.01	0.07	0.57	0.31	0.31	0.10	1.45	1.53
ST LT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HP/CAC	0.05	0.28	0.28	0.15	0.21	0.30	0.54	0.49	0.30	2.60	2.74
REFRIG				0.003	0.003	0.004	0.01	0.02	0.02	0.06	0.06
RAC						0.001	0.05	0.01	0.01	0.07	0.07
P. PUMP				0.31	0.19	0.29	0.15	0.11	0.07	1.12	1.18
CEIL INSL					0.11	0.16	0.16	0.19	0.12	0.74	0.78
TES							0.16	0.03	0.11	0.30	0.32
ABC							0.44	0.56	0.46	1.46	1.54
NCAS							0.00	0.00	0.01	0.01	0.01
CUST LEVEL	0.58	0.98	1.27	1.22	1.10	1.69	2.13	2.20	1.63	12.81	13.49
CUM	0.58	1.56	2.83	4.05	5.16	6.85	8.98	11.18	12.81		
METR LEVEL											

WINTER PEAK MW

PROGRAM	1981	1982	1983	1984	1985	1986	1987	1988	1989	CUST TOT	GEN TOT
RCS	0.08	0.10	0.04	0.70	0.22	0.10	0.03	0.00	0.00	1.27	1.34
FHS	0.18	0.22	0.20	0.19	0.40	0.34	0.28	0.57	0.51	2.89	3.04
CES	0.012	0.018	0.002	0.003	0.02	0.16	0.07	0.08	0.03	0.40	0.42
ST LT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HP/CAC	0.12	0.13	0.14	0.18	0.25	0.35	0.55	0.53	0.32	2.57	2.71
REFRIG				0.003	0.003	0.004	0.01	0.02	0.02	0.06	0.06
RAC						0.000	0.00	0.00	0.00	0.00	0.00
P. PUMP				0.09	0.05	0.09	0.04	0.03	0.02	0.32	0.34
CEIL INSL					0.11	0.16	0.16	0.19	0.12	0.74	0.78
TES							0.12	0.03	0.10	0.25	0.26
ABC							0.39	0.49	0.41	1.29	1.36
NCAS							0.00	0.00	0.01	0.01	0.01
CUST LEVEL	0.39	0.47	0.38	1.17	1.05	1.20	1.65	1.94	1.54	9.80	10.31
CUM	0.39	0.86	1.24	2.41	3.46	4.67	6.32	8.26	9.80		
METR LEVEL											

Cumulative avoided capacity $= \frac{13.49 + 10.31}{2} = 11.9$ MW

ORLANDO UTILITIES COMMISSION
FLORIDA MUNICIPAL POWER AGENCY
KISSIMMEE UTILITY AUTHORITY

DOCKET NO. 910382-EM

WITNESS: Gerald F. Erickson

Late Filed Exhibit No. 38

Description: List of cogenerator inquiries.

Company or Individual Name	Date
Pinellas County Resource Recovery	1978, 1979
Brevard County Resource Recovery	1978, 1980
Martin Company	October, 1980
Southern Fruit Company	1978-1981
Easy Manufacturing	March 1, 1981
Sheraton Twin Towers	March, 1981
Resource Planning Associates	March, 1981
NASA - Kennedy Space Center	April, 1982
Orlando International Airport	August, 1982
EmCon	January, 1984
Warren T. Francis	January, 1984
Energy Management Concepts and Services	September, 1984
Orlando Regional Medical Center	January, 1986
City of Orlando - McLeod Road Wastewater Plant	March, 1986
EnCoal	August, 1986
Marriot Hotels - Turner Power Group	1986, 1987
COICO, A.D. Robertson	August, 1987
Orange County Resource Recovery	November, 1987
Jim Stansberry	March, 1989
Barry Dyar	August, 1989
William Montgomery	1989
Universal Studios	1990
Air Products	March, 1990
Excalibur Development Group	May, 1991

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 38
COMPANY/
WITNESS: Erickson
DATE: 6/19/91

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 39
COMPANY/
WITNESS:
DATE: 6/18/91

- Energy Storage.
  - -- Battery.
  - -- Compressed Air.
  - -- Underground Pumped Hydro.

, taken from the literature, or obtained from vendors. Costs are

Cost estimates presented in this section were developed by Black & Veatch in January 1990 dollars unless otherwise designated. Capital costs are for overnight construction (not including interest during construction) unless noted.

Screening matrices for the five categories of technologies are presented in Tables 1A.5.1-1 through 1A.5.1-5. Three technologies were retained for screening: coal gasification combined cycle, solar thermal parabolic trough, and lead-acid battery storage.

1A.5.1.1 Coal Fueled Alternatives

The following coal fueled alternative technologies for power generation are discussed in this subsection.

- Gasification combined cycle.
- Pressurized fluidized bed combustion.
- Advanced pulverized coal.
- Gasification fuel cells.
- Gasification humid air turbine cycle.
- Coal liquefaction.
- Magnetohydrodynamics.

1A.5.1.1.1 Gasification Combined Cycle. A gasification combined cycle (GCC) system gasifies a solid fuel, producing a fuel gas for a combined cycle power generation system. Usable solid fuels include bituminous and subbituminous coals, or lignite. Fuel flexibility depends upon the gasifier used. Coal reacts in the gasifier with air or oxygen and water or steam to form raw syngas. A low Btu syngas (less than 200 Btu/scf, HHV basis) is produced by an air blown gasifier. A medium Btu gas (200 to 500 Btu/scf) is produced with an oxygen blown gasifier. The cleansed gas is used to fire a combined cycle power block. In an integrated gasification combined cycle (IGCC) system, steam generated in the heat recovery steam generator (HRSG) is augmented by steam produced in the gasification and gas cleanup system.

Large-scale demonstrations of IGCC plants include the 100 MW Cool Water plant in Daggett, California, which uses a Texaco gasifier, and the 160 MW GCC

#39

to gasify a combined coal/municipal sewage sludge feed. It will produce electricity, CO_2, alcohol, and ammonia.[2] Dow currently operates a 160 MW GCC unit in Plaquemine, Louisiana.[3] Shell is also developing a coal gasification process.

The Cool Water unit began operation in mid-1984. In 1988, the maximum permitted feed rate was 1,200 tons per day at a rating of 122 MW (gross).[1] The design coal was Illinois No. 6, although a variety of coals were tested at Cool Water. Carbon conversions exceeded 97 percent for four different coals. The demonstrated heat rate was 10,950 Btu/kWh. The capacity factor for the first eight months of 1988 was 71 percent. During July and August 1988, the capacity factors were 98.0 and 90.6 percent, respectively. The availability of the gasifier was 79.3 percent in 1987.

The Dow Syngas Project uses a coal/water slurry with 52 to 54 percent concentration. The plant uses a gasifier with two stages to improve carbon use and cold gas efficiency. Plant availability for its first full year of operation was 42 percent. Plant availability from May to September 1988 was 52 percent. Production records through September 1988 showed a daily production of 92 percent capacity and a 30-consecutive-day capacity of 65 percent.[3,4]

The Shell Development Company is developing the Shell Coal Gasification Process (SCGP). Shell's current demonstration unit is SCGP-1, located in Deer Park, Texas. SCGP-1 can gasify 250 tons per day of bituminous coals and 400 tons per day of lignites. Commercial Shell gasifiers are expected to have capacities ranging from 1,000 to 3,000 tons of coal per day.[5]

Another large-scale gasifier application within the United States is the 13,000-ton per day Dakota Gasification Plant in North Dakota. The plant uses 14 Lurgi gasifiers with a lignite feed, and produces synthetic natural gas. Lurgi gasifiers are also used in the SASOL I, II, and III plants in South Africa, where a total of 80,000 tons per day of coal are gasified to produce a number of products, including transportation fuels.

First commercial operation for GCC plants is projected to be in about 1994.[6]

1A.A.1.1.2 Cost and Performance Characteristics. Capital cost estimates for GCC systems vary with system size, design coal, gasifier manufacturer, and degree of integration, as well as plant location. Lowest capital cost estimates are at $1,210/kW for Dow gasifier systems and $1,120/kW for lignite and subbituminous burning plants with a Texas location.[7] No data are available in the public domain

, respectively, 8

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Shahla S. Speck
Exhibit No. 40 (SSS-1)
Page 1 of 1

REVISED JUNE 18, 1991

1997 RESOURCE AND DEMAND SUMMARY (MW)

	1989 APH	KNOWN CHANGE	CURRENT STATUS
FIRM SUMMER PEAK DEMAND	30,347	470	30,817
RESOURCES			
Firm Import From SOU	1,200	437	1,637
Firm QF/IPP	874	556	1,430
Utility Generation Without Stanton 2	35,223	(1,177)	34,046
TOTAL RESOURCES WITHOUT STANTON 2	37,297	(184)	37,113
RESERVE MARGIN WITHOUT STANTON 2	6,950	(654)	6,296
PLUS STANTON 2		440	440
RESERVE MARGIN WITH STANTON 2	6,950	(214)	6,736

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 40
COMPANY/ WITNESS: Speck
DATE: 6/19/91

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No.___ (FMP-1)

Corrections to the Curtis H. Stanton Energy Center Unit 2 Supplemental Site Certification Application

1. Page TC-21 should be changed to reflect the changes marked on the attached Page TC-21.

2. On Page 1A.4.3-1, Line 4, change "Docket 88004-EU" to "Docket 880004-EU".

3. On Page 1C.4.1-1, Line 5, change "Subsection 1C.3.0" to "Subsection 1A.3.0."

4. On Page 1C.4.4-1, Line 13, change "projection facilities" to "production facilities."

5. On Pages 1C.8.7-2 and 1C.8.7-3, Table 1C.8.7-1 should be relabeled Table 1C.8.2-1 and repaginated as 1C.8.2-5 and 1C.8.2-6.

6. Insert the attached pages 1C.8.2-7, 1C.8.2-8, 1C.8.2-9, 1C.8.2-10, 1C.8.7-2, 1C.9-4, 1C.9-5, 1C.9.6, and 1C.9-7.

7. On Page 1C.10.7-1, Line 8, change "Table 1C.D.2-2" to "Table 1C.D.2-1"

8. Page 1C.11.2-2 should be changed to reflect the changes marked on the attached page 1C.11.2-2.

9. Page 1C.E.6-3 should be repaginated as IC.E.6-4.

10. Page 1C.E.6-4 should be repaginated at IC.E.6-3.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 41
COMPANY/ WITNESS: Williams / Guarriello
DATE: 6/19/91

Contents (Continued)

Tables (Continued)

031591

Table 1C.11.2-1
Florida Municipal Power Agency Stanton 2 Analysis
Summary of Economic Analysis of Stanton 2 Participants

		1997-2010 Savings $(000)		1997-2021 Savings $(000)	
	Participation Level	Cumulative	Present Worth	Cumulative	Present Worth
Fort Pierce Utilities Authority, and City of Vero Beach	31.800	24,393	5,661 0.9 percent*	174,034	30,420 2.5 percent*
Homestead	15.900	5,572	3,063 1.6 percent*		
Utility Board, City of Key West	9.540	3,065	206 0.0 percent*	33,615	5,426 0.6 percent*
Lake Worth	7.950	10,278	3,522 1.4 percent*		
Starke	1.194	357	(39) -0.1 percent*	5,414	720 0.7 percent*
Total	66.384				

*Cumulative present worth savings as a percent of total cumulative present worth annual comparative revenue requirements.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (FMP-1)
Page 3 of 12

041191

FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

TABLE 1C.8.2-2
Page 1 of 2

PROJECTED COST OF STANTON 2
FOR PARTICIPANTS ON FPL SYSTEM

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fixed Costs															
1 Debt Service .... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	153.5	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
2 Interest Earnings ... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	-15.37	-20.52	-20.56	-20.59	-20.64	-20.69	-20.73	-20.78	-20.84
3 Facilities Use Fee .. $/kW	0.00	0.00	0.00	0.00	0.00	0.00	2.82	3.71	3.66	3.61	3.55	3.50	3.45	3.39	3.34
4 Renewals & Repl ..... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	2.04	2.85	2.98	3.13	3.27	3.43	3.59	3.76	3.94
5 Fixed O & M .... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	28.56	40.30	42.21	44.22	46.32	48.52	50.82	53.24	55.77
6 System A & G & Ins .. $/kW	0.00	0.00	0.00	0.00	0.00	0.00	3.33	4.65	4.87	5.10	5.34	5.59	5.86	6.14	6.43
7 Agency A & G .... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	3.33	4.65	4.87	5.10	5.34	5.59	5.86	6.14	6.43
8 OUC Wheeling .... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	7.63	10.32	10.48	10.63	10.79	10.95	11.12	11.29	11.46
9 Other Wheeling ...... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	20.52	27.84	28.44	29.04	29.64	30.24	30.96	31.68	32.40
10 Capacity Losses ..... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	12.38	16.71	16.90	17.10	17.30	17.51	17.74	17.97	18.22
11 Rating Adjustment ... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12 Total Fixed Costs ... $/kW	0.00	0.00	0.00	0.00	0.00	0.00	218.77	295.21	298.55	302.03	305.63	309.37	313.38	317.54	321.85
							-	34.94%	1.13%	1.17%	1.19%	1.22%	1.30%	1.33%	1.36%
Variable Costs															
13 Fuel .... $/MWh	0.00	0.00	0.00	0.00	0.00	0.00	28.90	30.30	31.80	34.30	36.10	38.00	40.00	42.00	44.20
14 Acid Rain Allowance $/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.12	1.17	1.22	1.27	1.32	1.37
15 Variable O & M ..... $/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.27	0.28	0.29	0.31	0.32	0.34	0.35	0.37
16 Energy Losses ...... $/MWh	0.00	0.00	0.00	0.00	0.00	0.00	1.75	1.83	1.92	2.14	2.25	2.37	2.50	2.62	2.76
17 Total Variable Costs $/MWh	0.00	0.00	0.00	0.00	0.00	0.00	30.90	32.40	34.00	37.86	39.83	41.91	44.10	46.29	48.69

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NPG-1)
Page 4 of 12

041191

FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

PROJECTED COST OF STANTON 2
FOR PARTICIPANTS ON FPL SYSTEM

Description		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Fixed Costs																	
1 Debt Service	$/kW	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
2 Interest Earnings ...	$/kW	-20.88	-20.96	-21.02	-21.09	-21.17	-21.25	-21.34	-21.43	-21.53	-21.64	-21.76	-21.88	-22.02	-22.15	-22.30	-22.47
3 Facilities Use Fee ..	$/kW	3.29	3.23	3.18	3.13	3.07	3.02	2.97	2.91	2.86	2.81	2.75	2.70	2.65	2.59	2.54	2.49
4 Renewals & Repl	$/kW	4.13	4.33	4.53	4.75	4.97	5.21	5.46	5.72	5.99	6.27	6.57	6.88	7.21	7.55	7.91	8.28
5 Fixed O & M	$/kW	58.42	61.19	64.10	67.14	70.33	73.67	77.17	80.84	84.68	88.70	92.91	97.33	101.95	106.79	111.86	117.18
6 System A & G & Ins ..	$/kW	6.73	7.05	7.39	7.74	8.11	8.49	8.90	9.32	9.76	10.22	10.71	11.22	11.75	12.31	12.89	13.51
7 Agency A & G	$/kW	6.73	7.05	7.39	7.74	8.11	8.49	8.90	9.32	9.76	10.22	10.71	11.22	11.75	12.31	12.89	13.51
8 OUC Wheeling	$/kW	11.63	11.80	11.98	12.16	12.34	12.53	12.71	12.90	13.10	13.29	13.49	13.70	13.90	14.11	14.32	14.54
9 Other Wheeling	$/kW	33.12	33.96	34.80	35.64	36.48	37.32	38.16	39.12	39.96	40.92	41.88	42.84	43.80	44.76	45.84	46.95
10 Capacity Losses	$/kW	18.47	18.74	19.02	19.31	19.62	19.93	20.26	20.60	20.96	21.33	21.72	22.12	22.54	22.98	23.44	23.92
11 Rating Adjustment ...	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12 Total Fixed Costs ...	$/kW	326.35	331.11	336.08	341.22	346.57	352.13	357.89	364.01	370.24	376.84	383.70	390.83	398.24	405.96	414.11	422.61
		1.40%	1.46%	1.50%	1.53%	1.57%	1.60%	1.64%	1.71%	1.71%	1.78%	1.82%	1.86%	1.90%	1.94%	2.01%	2.05%
Variable Costs																	
13 Fuel	$/MWh	46.50	48.90	51.40	54.10	56.90	59.80	62.90	66.20	69.60	73.10	76.90	80.90	85.10	89.40	94.10	99.05
14 Acid Rain Allowance	$/MWh	1.42	1.48	1.54	1.60	1.67	1.73	1.80	1.87	1.95	2.03	2.11	2.19	2.28	2.37	2.46	2.56
15 Variable O & M	$/MWh	0.39	0.40	0.42	0.44	0.46	0.49	0.51	0.53	0.56	0.59	0.61	0.64	0.67	0.71	0.74	0.77
16 Energy Losses	$/MWh	2.90	3.05	3.20	3.37	3.54	3.72	3.91	4.12	4.33	4.54	4.78	5.02	5.28	5.55	5.84	6.14
17 Total Variable Costs	$/MWh	51.21	53.83	56.56	59.51	62.57	65.74	69.12	72.72	76.43	80.25	84.40	88.76	93.33	98.02	103.14	108.53

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NPG-1)
Page 5 of 12

041191

FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

TABLE 1C.8.2-3
Page 1 of 2

PROJECTED COST OF STANTON 2
FOR PARTICIPANTS ON FPC SYSTEM

Description		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fixed Costs																
1 Debt Service	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	153.5	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
2 Interest Earnings ...	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	-15.37	-20.52	-20.56	-20.59	-20.64	-20.69	-20.73	-20.78	-20.84
3 Facilities Use Fee ..	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	2.82	3.71	3.66	3.61	3.55	3.50	3.45	3.39	3.34
4 Renewals & Repl	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	2.04	2.85	2.98	3.13	3.27	3.43	3.59	3.76	3.94
5 Fixed O & M	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	28.56	40.30	42.21	44.22	46.32	48.52	50.82	53.24	55.77
6 System A & G & Ins ..	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	3.33	4.65	4.87	5.10	5.34	5.59	5.86	6.14	6.43
7 Agency A & G	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	3.33	4.65	4.87	5.10	5.34	5.59	5.86	6.14	6.43
8 OUC Wheeling	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	7.63	10.32	10.48	10.63	10.79	10.95	11.12	11.29	11.46
9 Other Wheeling	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	20.52	27.84	28.44	29.04	29.64	30.24	30.96	31.68	32.40
10 Capacity Losses	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	13.21	17.82	18.03	18.24	18.45	18.68	18.92	19.17	19.43
11 Rating Adjustment ...	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12 Total Fixed Costs ...	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	219.60	296.33	299.68	303.17	306.78	310.53	314.56	318.74	323.07
								-	34.94%	1.13%	1.17%	1.19%	1.22%	1.30%	1.33%	1.36%
Variable Costs																
13 Fuel	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	28.90	30.30	31.80	34.30	36.10	38.00	40.00	42.00	44.20
14 Acid Rain Allowance	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.12	1.17	1.22	1.27	1.32	1.37
15 Variable O & M	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.27	0.28	0.29	0.31	0.32	0.34	0.35	0.37
16 Energy Losses	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	1.87	1.96	2.05	2.29	2.40	2.53	2.66	2.79	2.94
17 Total Variable Costs	$/MWh	0.00	0.00	0.00	0.00	0.00	0.00	31.02	32.52	34.13	38.00	39.98	42.07	44.26	46.46	48.88

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (PMP-1)
Page 8 of 12

FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

PROJECTED COST OF STANTON 2
FOR PARTICIPANTS ON FPC SYSTEM

Description		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Fixed Costs																	
1 Debt Service	$/kW	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
2 Interest Earnings ...	$/kW	-20.88	-20.96	-21.02	-21.09	-21.17	-21.25	-21.34	-21.43	-21.53	-21.64	-21.76	-21.88	-22.02	-22.15	-22.30	-22.47
3 Facilities Use Fee ..	$/kW	3.29	3.23	3.18	3.13	3.07	3.02	2.97	2.91	2.86	2.81	2.75	2.70	2.65	2.59	2.54	2.49
4 Renewals & Repl	$/kW	4.13	4.33	4.53	4.75	4.97	5.21	5.46	5.72	5.99	6.27	6.57	6.88	7.21	7.55	7.91	8.28
5 Fixed O & M	$/kW	58.42	61.19	64.10	67.14	70.33	73.67	77.17	80.84	84.68	88.70	92.91	97.33	101.95	106.79	111.86	117.18
6 System A & G & Ins ..	$/kW	6.73	7.05	7.39	7.74	8.11	8.49	8.90	9.32	9.76	10.22	10.71	11.22	11.75	12.31	12.89	13.51
7 Agency A & G	$/kW	6.73	7.05	7.39	7.74	8.11	8.49	8.90	9.32	9.76	10.22	10.71	11.22	11.75	12.31	12.89	13.51
8 OUC Wheeling	$/kW	11.63	11.80	11.98	12.16	12.34	12.53	12.71	12.90	13.10	13.29	13.49	13.70	13.90	14.11	14.32	14.54
9 Other Wheeling	$/kW	33.12	33.96	34.80	35.64	36.48	37.32	38.16	39.12	39.96	40.92	41.88	42.84	43.80	44.76	45.84	46.95
10 Capacity Losses	$/kW	19.70	19.99	20.29	20.60	20.92	21.26	21.61	21.98	22.35	22.75	23.17	23.60	24.04	24.51	25.00	25.52
11 Rating Adjustment ...	$/kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12 Total Fixed Costs ...	$/kW	327.58	332.36	337.35	342.51	347.88	353.46	359.24	365.39	371.63	378.26	385.15	392.31	399.75	407.49	415.67	424.20
		1.40%	1.46%	1.50%	1.53%	1.57%	1.60%	1.64%	1.71%	1.71%	1.78%	1.82%	1.86%	1.90%	1.94%	2.01%	2.05%
Variable Costs																	
13 Fuel	$/MWh	46.50	48.90	51.40	54.10	56.90	59.80	62.90	66.20	69.60	73.10	76.90	80.90	85.10	89.40	94.10	99.05
14 Acid Rain Allowance	$/MWh	1.42	1.48	1.54	1.60	1.67	1.73	1.80	1.87	1.95	2.03	2.11	2.19	2.28	2.37	2.46	2.56
15 Variable O & M	$/MWh	0.39	0.40	0.42	0.44	0.46	0.49	0.51	0.53	0.56	0.59	0.61	0.64	0.67	0.71	0.74	0.77
16 Energy Losses	$/MWh	3.09	3.25	3.42	3.59	3.78	3.97	4.17	4.39	4.61	4.85	5.10	5.36	5.64	5.92	6.23	6.55
17 Total Variable Costs	$/MWh	51.40	54.03	56.78	59.74	62.81	65.99	69.38	73.00	76.72	80.56	84.72	89.09	93.69	98.39	103.53	108.94

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (FMP-1)
Page 7 of 12

FLORIDA MUNICIPAL POWER AGENCY

TABLE 1C.8.7-1

PROJECTED FPL AND FPC WHOLESALE POWER AND TRANSMISSION SERVICE UNIT COSTS[1]

Calendar Year	FLORIDA POWER & LIGHT PARTIAL REQUIREMENTS[4] Demand[7] ($/kw-m)	FPL Energy Non-Fuel ($/mwh)	FPL Energy Fuel[8] ($/mwh)	FLORIDA POWER CORPORATION CONTRACT[5] Demand[9] ($/kw-m)	FPC Energy Non-Fuel ($/mwh)	FPC Energy Fuel[8] ($/mwh)	TRANSMISSION SERVICE[6] FPL ($/kw-m)	TRANSMISSION SERVICE[6] FPC ($/kw-m)
Actual Rates[2]:								
1988	12.93	6.07	18.77 [10]	7.36	4.05	18.19 [10]	1.84	1.34
1989	12.93	[illegible]	20.12 [10]	7.36	4.05	22.08 [10]	1.84	1.34
1990	12.93	6.07	21.11 [10]	7.36	4.05	22.33 [10]	1.84	1.34
Projected Costs[3]:								
1991	13.53	6.50	24.12	[illegible]	4.11	22.97	1.72	1.27
1992	14.42	6.88	24.05	7.63	4.20	26.06	1.95	1.32
1993	15.16	7.18	24.98	7.63	4.20	26.89	2.10	1.37
1994	15.51	7.31	26.69	8.11	4.48	30.57	2.16	1.43
1995	16.13	7.61	28.48	8.37	4.64	33.17	2.19	1.49
1996	17.91	8.53	28.90	8.86	4.92	38.39	2.23	1.56
1997	18.09	8.58	31.69	9.36	5.22	40.44	2.28	1.64
1998	20.00	9.58	33.58	10.02	5.59	45.31	2.32	1.72
1999	20.38	9.74	36.60	12.11	6.75	46.15	2.37	1.80
2000	21.04	10.06	40.12	12.34	6.89	50.20	2.42	1.89
2001	23.17	11.17	42.40	13.99	7.81	52.58	2.47	1.97
2002	25.41	12.34	45.77	13.89	7.76	56.04	2.52	2.07
2003	25.98	12.60	48.42	14.09	7.87	58.79	2.58	2.17
2004	28.39	13.85	52.16	14.26	7.97	62.61	2.64	2.28
2005	30.63	15.01	55.17	14.58	8.15	65.68	2.70	2.40
2006	33.10	16.29	58.93	14.86	8.31	69.56	2.76	2.47
2007	33.37	16.39	61.95	17.15	9.60	72.59	2.83	2.54
2008	35.67	17.57	66.22	17.28	9.67	76.86	2.90	2.68
2009	37.66	18.58	69.60	17.39	9.73	80.30	2.97	2.83
2010	37.92	18.67	74.43	19.68	11.02	84.75	3.04	2.98
2011	40.22	19.86	79.17	20.62	11.55	89.31	3.11	3.12
2012	42.66	21.13	84.22	21.61	12.11	94.11	3.18	3.26
2013	45.25	22.48	89.59	22.64	12.69	99.17	3.26	3.42
2014	48.00	23.91	95.30	23.72	13.30	104.50	3.33	3.58
2015	50.91	25.43	101.38	24.85	13.94	110.12	3.41	3.74
2016	54.00	27.06	107.84	26.04	14.61	116.04	3.49	3.92
2017	57.27	28.78	114.71	27.28	15.31	122.28	3.57	4.10
2018	60.75	30.62	122.03	28.59	16.05	128.85	3.65	4.29
2019	64.43	32.57	129.81	29.95	16.82	135.78	3.73	4.49
2020	68.34	34.65	138.08	31.39	17.63	143.08	3.82	4.70

[1] Based on the principal considerations and assumptions.
[2] Actual rates in effect in 1988, 1989 and 1990.
[3] Projected unit costs based upon rate setting practices similar to those used to develop the actual rates shown. The projected rates in effect in any year would depend on the timing and results of rate filings made at the Federal Energy Regulatory Commission ("FERC") by the Company or by its customers.
[4] Projected unit costs under Florida Power & Light's ("FPL") FERC electric tariff for partial requirements purchases. Projected costs are at the customers high voltage delivery point and include transmission costs and losses over the FPL system.
[5] Projected unit costs under the Florida Power Corporation Agreement for Partial Requirements Resale Service, Transmission/Distribution Service and Demand and Energy Losses Service (the "FPC Agreement"). Costs are at the FPC generation level and do not include FPC transmission or transmission losses. Costs shown for FPC cannot be compared to costs shown for FPL without adjusting for transmission costs, capacity and energy losses, and differing billing demand criteria.
[6] Projected unit costs for firm transmission of bulk power to a high voltage delivery point.
[7] Projected unit costs per kW of noncoincident peak demand at the delivery level.
[8] Projected system average annual fuel costs at the delivery level.
[9] Projected unit costs per kW of coincident peak demand as is used in the demand true-up provisions of the FPC Agreement.
[10] Fuel costs are based on estimated system average cost for 1988 and 1989 and projected costs for 1990.

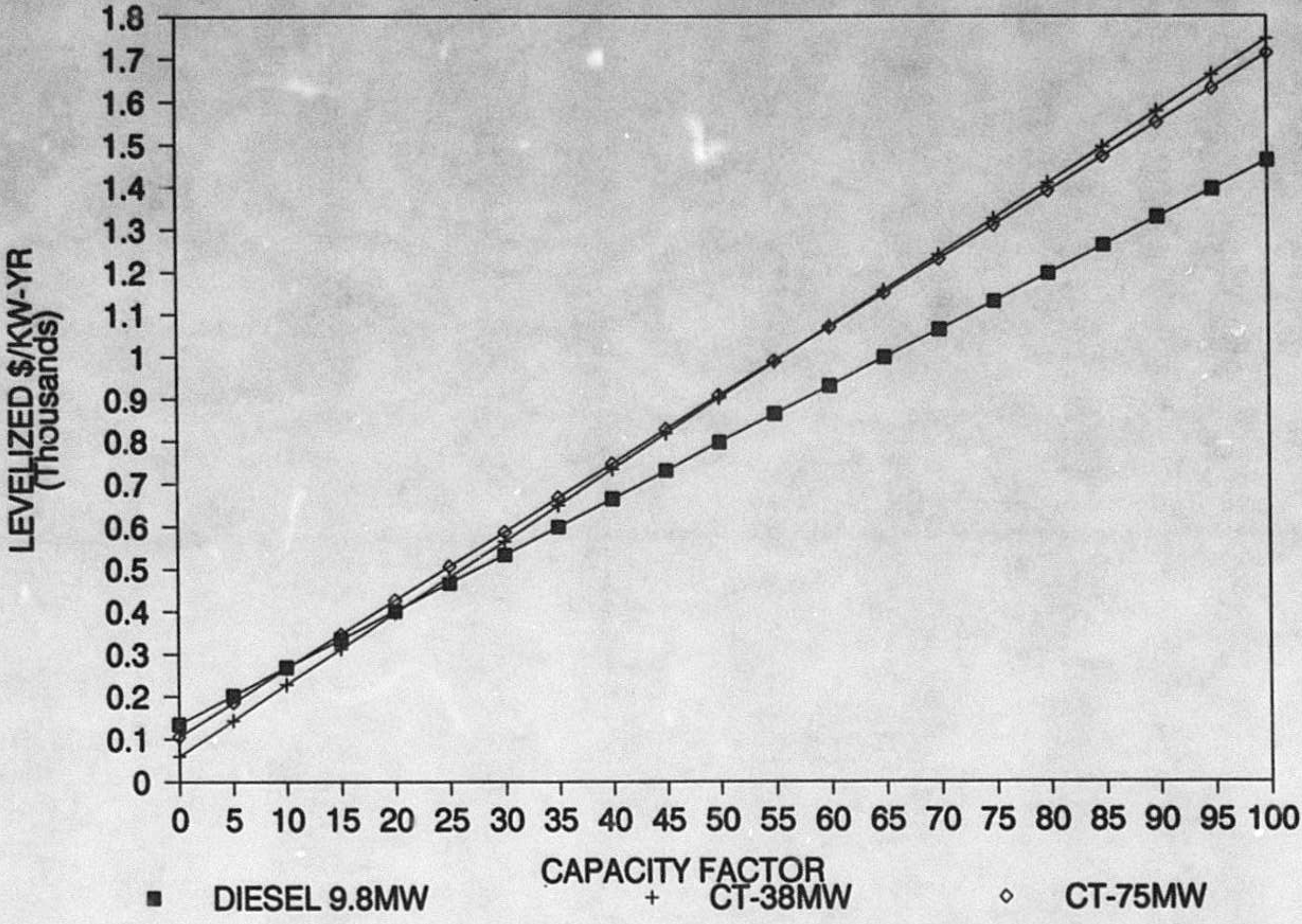
Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NPG-1)
Page 8 of 12

041191

FIGURE 1C.9-1

GENERATION SCREENING CURVE COMPARISIONS

(PEAK LOAD RESOURCES)

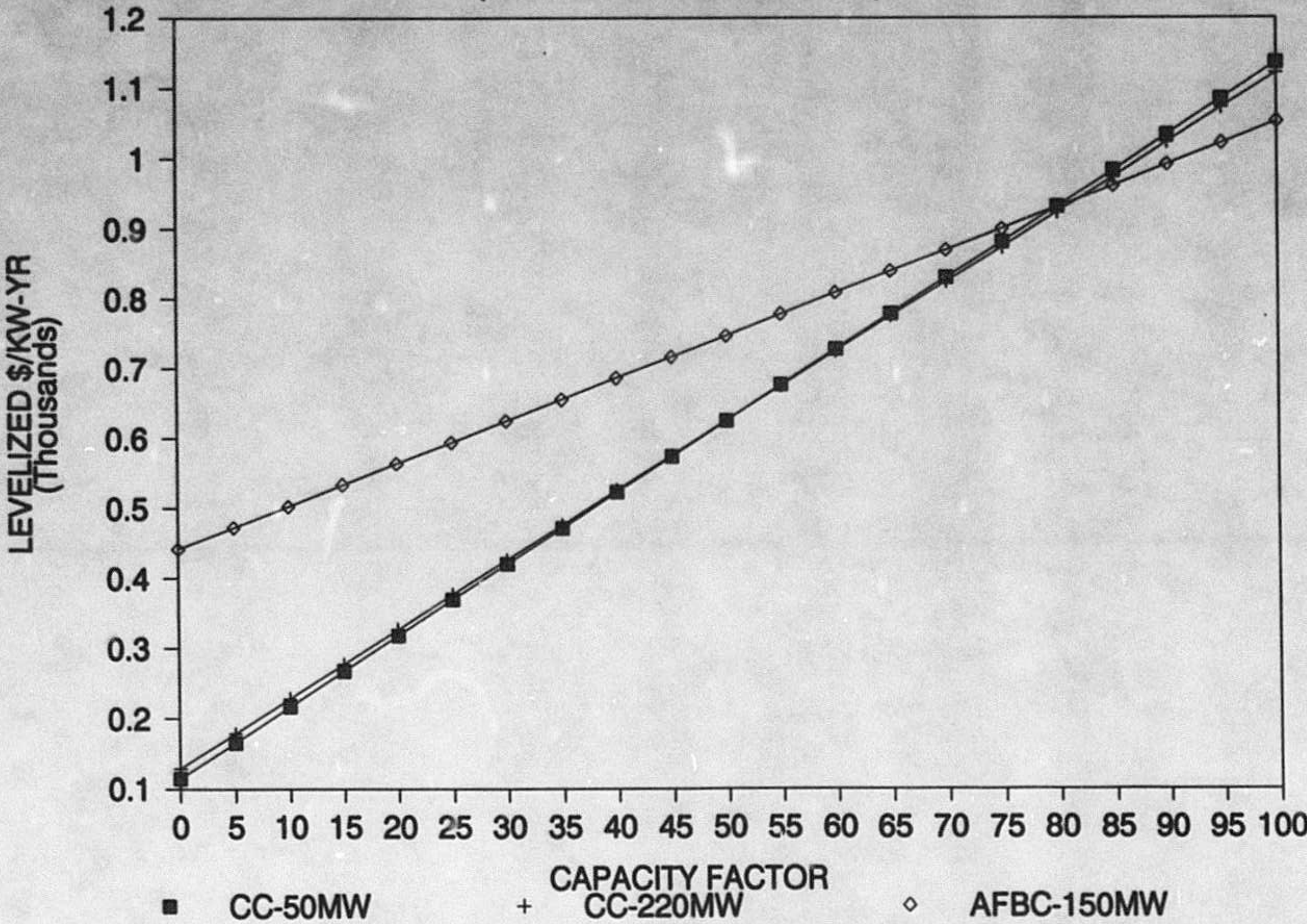


Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NMP-1)
Page 9 of 12

041191

FIGURE 1C.9-2

GENERATION SCREENING CURVE COMPARISIONS
(BASE LOAD RESOURCES)



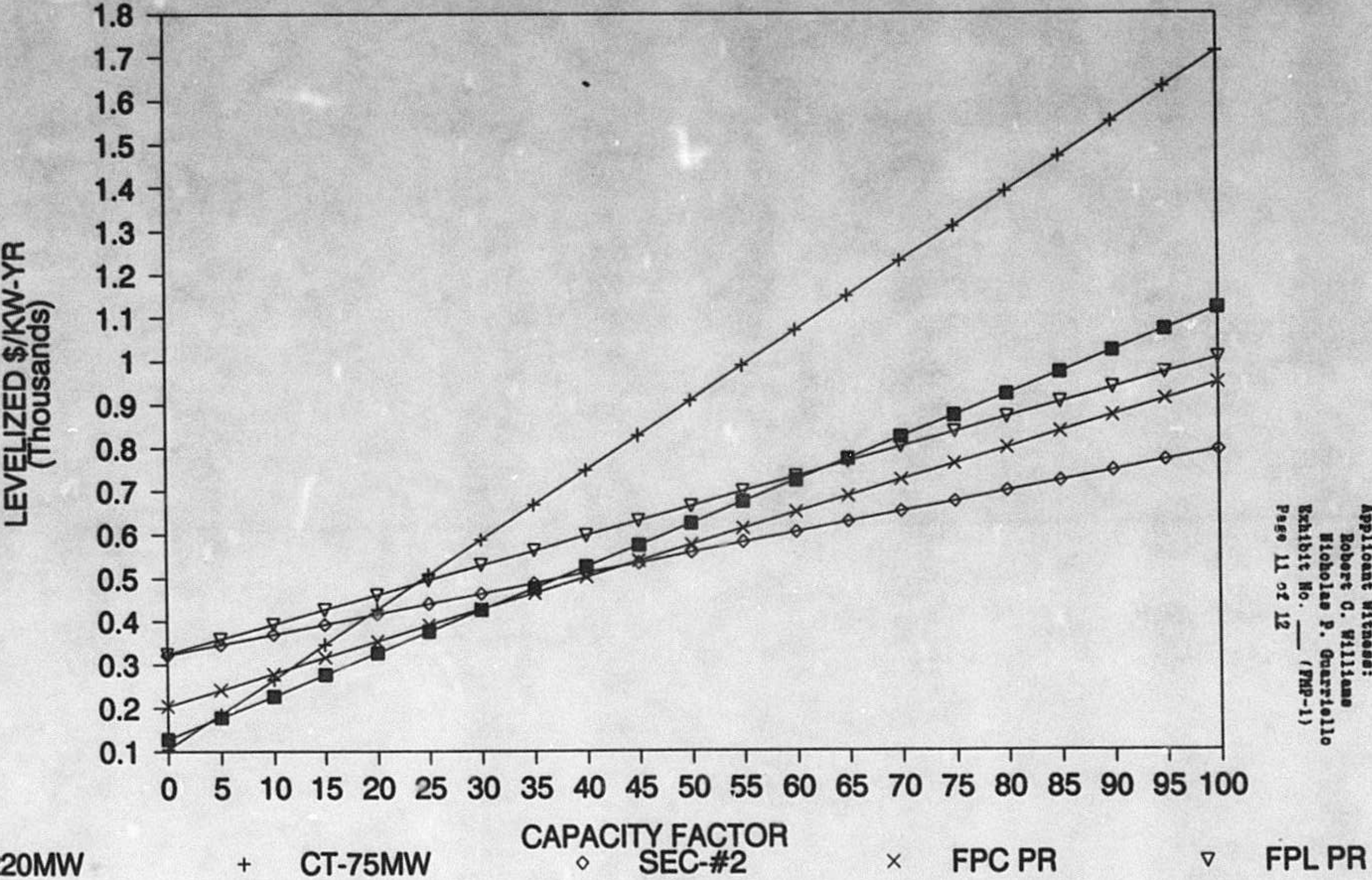
Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NPG-1)
Page 10 of 12

041191

FIGURE 1C.9-3

COMPARISION OF TECHNOLOGIES

Screening Curve - 1997 In Service



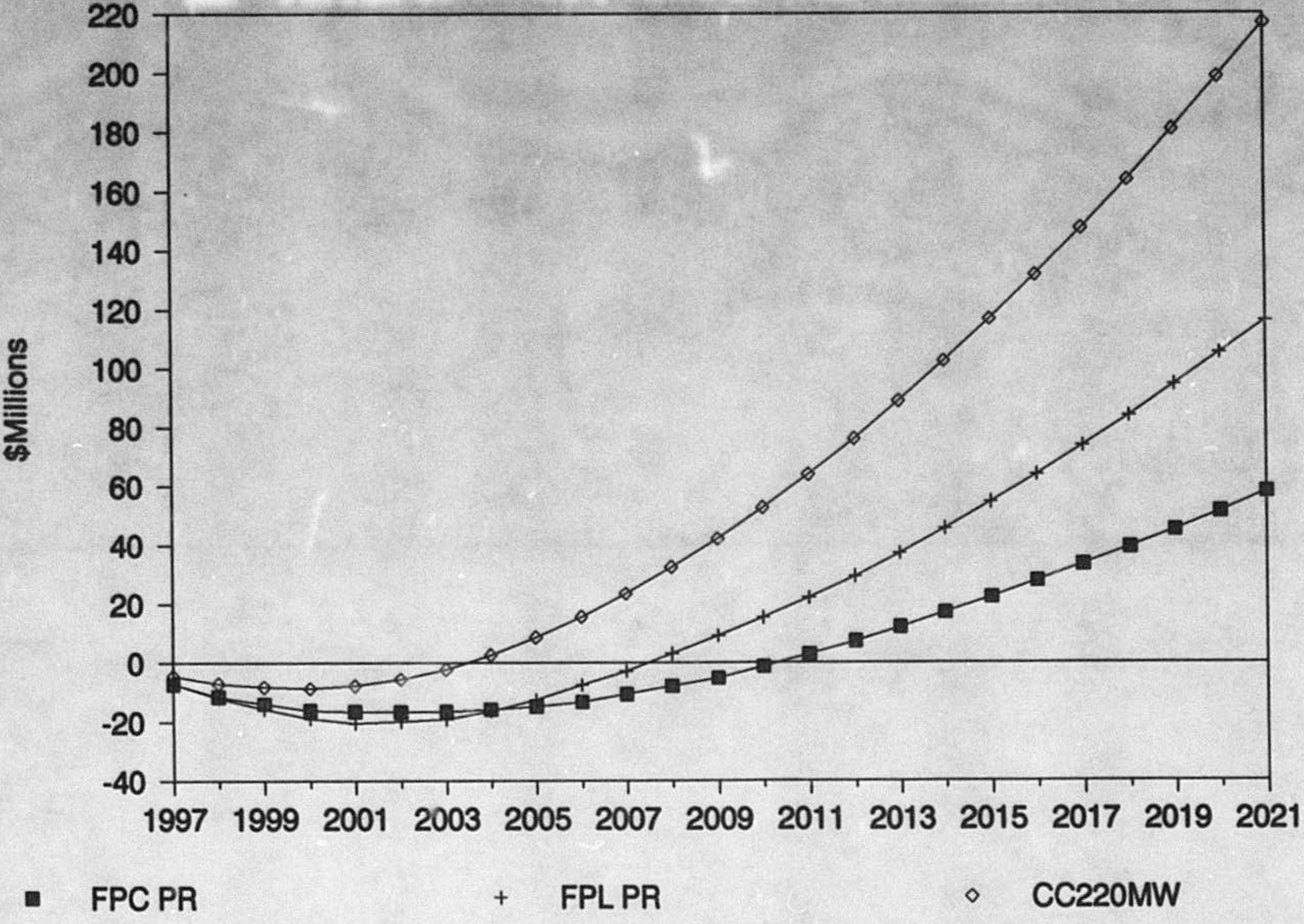
Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (NMP-1)
Page 11 of 12

041191

FIGURE 1C.9-4

DIFFERENCE IN PWRR

AS COMPARED TO STANTON 2



Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (FMP-1)
Page 12 of 12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 42
COMPANY/
WITNESS: William Quarrelle
DATE 6/19/91

Florida Municipal Power Agency
Member Interest and Entitlements in Stanton 2

Utility	FY 89 Peak Load	Unit 2 Interest MW	Unit 2 Entitlements MW	Interest Not Served MW
All-Requirements Project	393	75	21.5	(53.5)
Fort Pierce	106	30	15.9	(14.1)
Gainesville	296	0	0	0.0
Homestead	49	15	15.9	0.9
Key West	83	12	9.5	(2.5)
Kissimmee*	148	33	0	(33.0)
Lakeland	469	0	0	0.0
Lake Worth	74	15	8.0	(7.0)
New Smyrna Beach	72	20	0	(20.0)
Saint Cloud	54	35	0	(35.0)
Sebring	54	0	0	0.0
Starke	12	5	1.2	(3.8)
Tallahassee	403	75	0	(75.0)
Vero Beach	132	30	15.9	(14.1)
Total	2,345	345	87.8	(257)

* Kissimmee interest does not include 17 MW expected through direct participation in Unit 2.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness:
Robert C. Williams
Nicholas P. Guarriello
Exhibit No. ___ (PMP-2)
Page 1 of 1

DATA REQUEST - PETITIONERS
STANDARD OFFER CONTRACTS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 910382-EM EXHIBIT NO. 43
COMPANY/
WITNESS: Wms. / Guarriello
DATE: 6/19/91

INDEX OF CONTRACTS AND AGREEMENTS

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING FACILITY RATE SCHEDULE CG-1

AVAILABILITY:

This Rate Schedule is available throughout the entire territory served by Orlando Utilities Commission (OUC). OUC will purchase energy offered by any QF within the territory served by OUC under the provisions of this schedule or at contract negotiated rates. OUC will negotiate and may contract with a QF outside OUC's service territory where such negotiated contracts are, as determined by OUC, in the best interest of OUC.

APPLICATION:

The Rate Schedule is applicable to any QF producing energy for sale to OUC on an as-available basis pursuant to the terms and conditions of this Rate Schedule and OUC's Standard Offer Contract for the Purchase of As-Available Energy from a Qualifying Facility ("SOC-1") or a separately negotiated contract. As-Available Energy is energy produced and sold by a QF on an hour-by-hour basis for which firm commitments as to the time, quantity, or reliability of delivery are not required. Criteria for achieving QF status shall be those set out in the Federal Energy Regulatory Commission Rules 292.201 through 292.207, effective March 20, 1980.

CHARACTER OF SERVICE:

Purchases within the territory served by OUC shall be, at the option of OUC, single or three phase, 60 hertz, alternating current at standard available voltage. Purchases from outside the territory served by OUC shall be three phase, 60 hertz, alternating current at the voltage level available at the interchange point between OUC and the utility delivering As-Available Energy from the QF.

Continued on Sheet No. 7.002

The calculation of payments to the QF 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 purchases by OUC for that hour. All purchases from QF shall be adjusted for losses from the point of metering to the appropriate location on OUC's electric system.

C. <u>Negotiated Rates</u>
Upon agreement by both OUC and the QF, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

Continued on Sheet No. 7.003

Continued from Sheet No. 7.002

DELIVERY VOLTAGE ADJUSTMENT:

Energy payments to QF's within OUC's service territory shall be adjusted for losses to the appropriate locations on OUC's electric system based on the delivery voltage level using the following loss adjustment factors:

Qualifying Facility Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery (115 kV and 230 kV)	1.0163
Primary Voltage Delivery (34,500 or 12,500 volts)	1.0204
Secondary Voltage Delivery (Less than 12,500 volts)	1.0493

These factors will be based on OUC's most recent annual data for that applicable system average loss percentage factor. If, in OUC's judgment, the use of average losses would not result in equitable compensation for losses incurred, incremental losses attributed to the transaction may be used. When incremental losses are to be used, the QF shall be so advised at least 30 days prior to the transaction.

Continued on Sheet No. 7.004

Continued from Sheet No. 7.003

METERING REQUIREMENTS

QF's within the territory served by OUC shall be required to pay all costs associated with meters necessary to measure their energy production. Energy purchases from QF's outside the territory served by OUC shall be measured as the quantities scheduled for interchange to OUC by the utility delivering As-Available Energy to OUC on behalf of the QF.

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

For QF's with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on the product of (1) OUC's actual avoided energy rate for each hour during the month; (2) the quantity of energy sold by the QF during that hour; and (3) the appropriate delivery voltage adjustment factor.

For QF's 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 OUC's actual hourly avoided energy rates for the on-peak and off-peak periods during the month; (2) the quantity of energy sold by the QF during on-peak and off-peak periods, respectively; and (3) the appropriate delivery voltage adjustment factor.

For QF's with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of (1) the average of OUC's actual hourly avoided energy rate for the off-peak periods during the month; (2) the quantity of energy sold by the QF during the month; and (3) the appropriate delivery voltage adjustment factor.

For a time-of-day metered QF, 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., clock time. All hours not mentioned above and all hours of the holidays of New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

Continued on Sheet No. 7.005

Continued from Sheet No. 7.004

TERMS OF PAYMENT:

A statement covering the charges and payments due the QF shall be prepared and rendered monthly by OUC, and payment normally will be made by the twentieth business day following the end of the billing period or within ten (10) days of mailing (as determined by post-mark), whichever is later.

CHARGES TO QUALIFYING FACILITY:

A. Charges for Additional Services
OUC shall charge and collect for additional services requested by the QF to be provided by OUC. Such charges and collections shall be in accordance with OUC's applicable rate schedule(s) which rate schedules by reference become a part of this Rate Schedule, and which rate schedule(s) may at OUC's option be revised from time to time.

B. Interconnection Charge for Non-Variable Utility Expenses
The QF shall bear the cost required for interconnection including the cost of metering.

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

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

Continued on Sheet No. 7.006

Continued from Sheet No. 7.005

TERMS OF SERVICE:

1. It shall be the QF's responsibility to inform OUC of any change in its electric generation capability.

2. Any electric service delivered by OUC to the QF 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 OUC's rules and regulations and the following:

   a. In the first year of operation, the security deposit shall be based upon the singular month in which the QF's projected purchases from OUC exceed, by the greatest amount, OUC's estimated purchases from the QF. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon inter-connection.

   b. For each year thereafter, a review of the actual sales and purchases between the QF and OUC 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 QF exceed the actual sales to OUC in that month.

4. OUC shall specify the point of interconnection and the voltage level.

5. OUC will, under the provisions of this Rate Schedule, require a Parallel Operation Agreement between the QF and the electric utility in whose service territory the QF's generating facility is located. The QF shall recognize that its generation facility located in OUC's service territory may exhibit unique interconnection requirements which will be separately evaluated by OUC, modifying OUC's "Safety and Technical Standards for Parallel Operation of a Qualifying Facility" where applicable.

6. Service under this Rate Schedule is subject to the rules and regulations of OUC.

Continued on Sheet No. 7.007

Continued from Sheet No. 7.006

SPECIAL PROVISIONS:

1. Special contracts deviating from the above standard rate schedule are allowable provided they are agreed to by OUC.

2. A QF located within OUC's service territory may sell As-Available Energy to a utility other than OUC when adequate transmission capacity is available on OUC's system. When such conditions exist, OUC will provide transmission wheeling service to deliver the QF's power to the purchasing utility or to an intermediate utility. In addition, OUC will provide transmission wheeling service through its service territory, when adequate transmission capacity exists, for a QF located outside OUC's service territory, for delivery of the QF's power to the purchasing utility or to an intermediate utility. In either case, OUC will charge for wheeling QF As-Available Energy pursuant to the provisions of OUC's Rate Schedule CG-3 for Transmission Service for a QF.

3. OUC shall be relieved of its obligation to purchase and pay for As-Available Energy from a QF when purchases result in higher costs to OUC than without such purchases, and where service to OUC's other customers may be impaired by such purchases. On such occasions OUC shall notify the QF as soon as possible or practical.

STANDARD RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM QUALIFYING FACILITY RATE SCHEDULE CG-2

AVAILABILITY:

This Rate Schedule is available to Qualifying Facilities ("QF") throughout the entire territory served by the Orlando Utilities Commission (OUC). OUC will purchase Firm Capacity and Energy offered by any QF within the territory served by OUC under the provisions of this Rate Schedule or at contract negotiated rates to the extent such purchases are in the best interest of OUC. OUC will negotiate and may contract for the purchase of Firm Capacity and Energy from a QF outside OUC's service territory where such purchases are, as determined by OUC, in the best interest of OUC. This Rate Schedule will not be available after March 12, 1991, or a date seventy (70) months prior to the designated in-service date of OUC's Avoided Resource, whichever is later.

APPLICATION:

This Rate Schedule is applicable to any QF, irrespective of its location, producing capacity and energy for sale to OUC on a firm basis pursuant to the terms and conditions of this Rate Schedule and OUC's "Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility" ("SOC-2"), or a separately negotiated contract. Firm Capacity and Energy are capacity and energy produced and sold by a QF pursuant to SOC-2 or a negotiated contract and subject to contractual provisions as to quantity, time, and reliability of delivery. Criteria for achieving QF status shall be those set out in Federal Energy Regulatory Commission Rules 292.201 through 292.207, effective March 20, 1980.

CHARACTER OF SERVICE:

Purchases within the territory served by OUC shall be, at the option of OUC, single or three phase, 60 hertz, alternating current at standard available voltage. Purchases from outside the territory served by OUC shall be three phase, 60 hertz, alternating current at the voltage level available at the interconnection point between OUC and the utility delivering Firm Capacity and Energy from the QF.

Continued on Sheet No. 7.021

Continued from Sheet No. 7.020

LIMITATION OF SERVICE:

Purchases under this Rate Schedule are subject to OUC's need for Firm Capacity and Energy. The need for Firm Capacity, as determined by OUC planning studies, is 330 MW beginning January 1, 1997. Until such time as this need is satisfied, but no later than March 12, 1991, OUC will subscribe Firm Capacity and Energy offered by any QF under the provisions of this schedule.

Service under this Rate Schedule is limited to those QF's which:

A. At a point in time not later than seventy (70) months prior to the designated in-service date of OUC's Avoided Resource, execute a SQC-2 for the purchase of Firm Capacity and Energy by OUC; and

B. Commit to commence deliveries of Firm Capacity and Energy to OUC no later than two years before the designated in-service date of OUC's Avoided Resource and to continue such deliveries through at least ten years beyond the designated in-service date of OUC's Avoided Resource.

In addition to the above, an option for early capacity payments shall not exceed seventy (70) months prior to the designated in-service date of OUC's Avoided Resource.

RATES FOR PURCHASES BY OUC:

Firm Capacity and Energy are purchased at a unit cost, in dollars per kilowatt per month and cents per kilowatt hour, respectively, based on the value of deferring additional capacity resource(s) for OUC. For the purpose of this Rate Schedule, the Avoided Resource has been designated by OUC as a 440 MW net coal-fueled unit, of which OUC would require up to 330 MW to meet its own load requirements. For purposes of this schedule, the Avoided Resource would have a designated in-service date of January 1, 1997. Appendix A of this Rate Schedule describes the methodology used to calculate payment schedules and other general terms and conditions applicable to OUC's SOC-2.

Continued on Sheet No. 7.022

Continued from Sheet No. 7.021

A. Firm Capacity Rates

Two options, A and B, as set forth below, are available for payment for Firm Capacity which is produced by the QF and delivered to OUC. The QF may select either of two payment options: (A) Normal Payment or (B) Early Payment, both as set forth in Appendix A. Option A or B, once selected by the QF, shall remain in effect for the term of the contract between the QF and OUC. Normal and early payment schedules contain the monthly rate per kilowatt of Firm Capacity the QF has contractually committed to deliver to OUC and are based on a minimum contract term which extends ten (10) years beyond the designated in-service date of OUC's Avoided Resource.

Payment schedules are based on the value of a year-by-year deferral of OUC's Avoided Resource with a designated in-service Date of January 1, 1997.

The QF shall select the month and year in which the delivery of Firm Capacity and Energy to OUC is to commence (must commence at least two years before the designated in-service date of OUC's Avoided Resource) and capacity payments are to start. OUC will provide the QF 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.

Continued on Sheet No. 7.023

Continued from Sheet No. 7.022

B. Energy Rates

1. Payments Prior to January 1, 1997 (designated in-service date of OUC's Avoided Resource):

The energy rate in cents per kilowatt-hour (¢/kWh) shall be based on OUC's actual hourly avoided energy costs which are calculated by OUC. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for losses reflecting delivery to the appropriate location on OUC's electric system. When transactions with other utilities take place, the incremental costs are calculated after purchases from other utilities or before sales to other utilities.

The calculation of payments to the QF 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 purchases by OUC for that hour. All purchases from QF shall be adjusted for losses from the point of metering to the appropriate location on OUC's electric system.

2. Payments Starting on January 1, 1997 (designated in-service date of OUC's Avoided Resource):

The energy rate in cents per kilowatt-hour (¢/kWh), shall be the lesser of an hour-by-hour comparison of: (a) OUC's actual avoided hourly energy costs, or (b) OUC's Avoided Resource's applicable fuel costs, including identifiable variable operation and maintenanace expenses. OUC's Avoided Resource's applicable fuel costs, in cents per kilowatt-hour (¢/kWh), shall be determined as the product of (1) the average monthly inventory charge-out price of coal burned at either (A) the most recent coal unit placed in commercial operation in which OUC has an ownership interest or (B) if (A) is not in operation, the most recent coal unit similar to OUC's planned Avoided Resource placed in commercial operation by an electric utility in Florida, and (2) the average annual net heat rate for the unit identified in (1) above.

Continued on Sheet No. 7.024

Continued from Sheet No. 7.023

Calculation of payments to the QF shall be based on the sum, over all hours of the billing period, of the product of each hours' appropriate avoided cost (Item (a) or Item (b) in the preceding paragraph) times the purchases by OUC for that hour. All purchases shall be adjusted for losses from the point of metering to the appropriate location on OUC's electric system. In the case of item (a) in the preceding paragraph, when transactions with other utilities take place, the incremental costs are calculated after purchases from other utilities or before sales to other utilities.

Continued on Sheet No. 7.025

Continued from Sheet No. 7.024

PERFORMANCE CRITERIA:

Payments for firm capacity are subject to the QF's ability to comply with and maintain the performance criteria set forth in SOC-2 and as follows:

A. Commercial In-Service Date

Capacity payments shall not commence until the QF has attained and demonstrated commercial in-service status. The commercial in-service date of a QF shall be defined as the first day of the month following the successful demonstration of the QF maintaining an hourly kilowatt (kW) output, as metered at the point of interconnection with OUC, equal to or greater than the QF's Actual Committed Capacity for a test period as set forth in SOC-2. A QF shall coordinate the selection of the test period and operation of its facility during such test period with OUC to insure that the performance of the QF during this test period is reflective of the anticipated operation of the QF.

B. Capacity Factor

Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly by OUC in accordance with the capacity payment rate option(s) selected by the QF and subject to the provision that the QF maintains a minimum seventy percent (70%) capacity factor on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours. (See Appendix A for calculation of capacity factor). Failure to achieve these capacity factors shall result in the QF's forfeiture of payments for Firm Capacity during the month in which such failure occurs. Where early capacity payment option has been elected and starting with the month of March 1991 (the first month the QF is eligible for such early capacity payments), failure of the QF to maintain capacity factors stated above shall also result in payments by the QF to OUC. The amount of such payments shall be equal to the difference between: (1) what the QF would have been paid had it elected the normal payment option starting January 1, 1997 (the designated in-service date of OUC's Avoided Resource); and (2) what the QF would have been paid pursuant to the early payment option had it maintained the capacity factor performance criteria.

Continued on Sheet No. 7.026

Continued from Sheet No. 7.025

All capacity payments made by OUC prior to January 1, 1997 (the designated in-service date of OUC's Avoided Resource) are considered "early payments." The owner and/or operator of the QF, as designated by OUC, shall secure its obligation to repay, with interest, the cumulative amount of early capacity payments in the event the QF defaults under the terms of its Standard Offer Contract with OUC. OUC will provide monthly summaries of the total outstanding balance of such security obligations. The types of security instruments which are acceptable to OUC are indicated in Appendix A.

C. Additional Criteria

1. The QF shall provide to OUC prior to March 1 for the next fiscal year or at other times requested by OUC, monthly generation estimates;
2. The QF shall promptly update its yearly generation schedule and maintenance schedule as and when any changes are determined necessary;
3. The QF shall agree to reduce generation or take other appropriate action as requested by OUC for safety reasons or to preserve system integrity;
4. The QF shall coordinate the delivery of its generated output and scheduled outages with OUC;
5. The QF shall comply with the reasonable requests of OUC regarding daily or hourly communications;
6. The QF shall provide all necessary information including but not limited to data acquisition for real time telemetry and acquisition of actual generation output of the Facility requested by OUC to implement and administer this Rate Schedule and other applicable rate schedule(s); and
7. The QF's maximum hourly output shall not exceed the Actual Committed Capacity defined in its Standard Offer Contract by more than five percent (5%).
8. The QF shall adjust reactive power flow in the interconnection as may be reasonably required by OUC or the electric utility with which the QF has signed a Parallel Operation Agreement within the range of 90% leading to 85% lagging power factor unless otherwise provided in the Parallel Operation Agreement.

Continued on Sheet No. 7.027

Continued from Sheet No. 7.026

DELIVERY VOLTAGE ADJUSTMENTS:

Energy payments to QF's within OUC's service territory shall be adjusted to the appropriate location on OUC's electric system based on the delivery voltage level using the following adjustment factors:

Qualifying Facility Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery (115 kV and 230 kV)	1.0163
Primary Voltage Delivery (34,500 volts or 12,500 volts)...........	1.0204
Secondary Voltage Delivery (less than 12,470 volts)..................	1.0493

These factors will be based on OUC's most recent annual data for the applicable system average loss percentage factor. If, in OUC's judgment, the use of average losses would not result in equitable compensation for losses incurred, incremental losses attributed to the transaction may be used. When incremental losses are to be used, the QF shall be so advised at least 30 days prior to the transaction.

METERING REQUIREMENTS:

QF's within the territory served by OUC shall be required to pay all costs associated with meters necessary to measure their energy production. Energy purchases from QF's outside the territory served by OUC shall be measured as the quantities scheduled for interchange to OUC by the utility delivering Firm Capacity and Energy to OUC on behalf of the QF.

Hourly recording meters shall be required for all QF's delivering firm energy.

TERMS OF PAYMENT:

A statement covering the charges and payments due the QF shall be prepared and rendered monthly by OUC, and payment normally will be made by the twentieth business day following the end of the billing period or within ten (10) days of mailing (as defined by postmark), whichever is later.

Continued on Sheet No. 7.028

Continued from Sheet No. 7.027

CHARGES TO QUALIFYING FACILITY:

A. Charges for Additional Services
OUC will charge and collect for additional services requested by the QF to be provided by OUC. Such charges and collections shall be in accordance with OUC's applicable rate schedule(s) which rate schedules by reference become a part of this Rate Schedule, and which rate schedule(s) may at OUC's option be revised from time to time.

B. Interconnection Charge for Non-Variable Utility Expenses
The QF shall bear the cost required for the interconnection facilities including the cost of metering and the costs associated with eliminating any impairment or reduction of the electric power transfer capability of OUC's transmission system, resulting from or attributable to the interconnection of the QF.

C. Interconnection Charge for Variable Utility Expenses
The QF shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These expenses include (a) OUC's inspections of the facilities, and (b) ownership costs of any equipment beyond that which would be required to provide normal electric service to the QF if no sales to OUC were involved.

D. Taxes and Assessments
The QF shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which OUC is liable as a result of its purchases of Firm Capacity and Energy produced by the QF.

TERMS OF SERVICE:

1. It shall be the QF's responsibility to inform OUC of any change in its electric generation capability.

2. Any electric service delivered by OUC to the QF shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall prevail.

Continued on Sheet No. 7.029

Continued from Sheet No. 7.028

3. A security deposit will be required in accordance with OUC's rules and regulations and the following:

   a. In the first year of operation, the security deposit should be based upon the singular month in which the QF's projected purchases from OUC exceed, by the greatest amount, OUC's estimated purchases from the QF. 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 QF and OUC should 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 QF exceed the actual sales to OUC in that month.

4. OUC shall specify the point of interconnection and voltage level.

5. OUC will, under the provisions of this Rate Schedule, require a Parallel Operation Agreement between the QF and the electric utility in whose service territory the QF's generating facility is located. The QF shall recognize that its generation facility located in OUC's service territory may exhibit unique interconnection requirements which will be separately evaluated by OUC, modifying OUC's "Safety and Technical Standards for Parallel Operation of a Qualifying Facility" where applicable.

6. Service under this Rate Schedule is subject to the rules and regulations of OUC.

Continued on Sheet No. 7.030

Continued from Sheet No. 7.029

SURETY BOND REQUIREMENTS:

OUC requires that when early capacity payments are elected, the QF must provide assurance of repayment of early capacity payments in the event the QF is unable to meet the terms and conditions of its contract. Depending on the nature of the QF operation, financial health and solvency, and its ability to meet the terms and conditions of OUC's SOC-2, one of the following may constitute an equivalent assurance of repayment:

(1) Surety Bond;
(2) Escrow;
(3) Irrevocable Letter of Credit.

SPECIAL PROVISIONS:

1. Special contracts deviating from the above standard rate schedule are allowable provided they are agreed to by OUC.

2. A QF located within OUC's service territory may sell Firm Capacity and Energy to a utility other than OUC when adequate transmission capacity is available on OUC's system. In addition, OUC will provide transmission wheeling service through its service territory, when adequate transmission capacity exists, for a QF located outside OUC's service territory, for delivery of the QF's power to the purchasing utility or to an intermediate utility. When such conditions exist, OUC will provide transmission wheeling service to deliver the QF's power to the purchasing utility or to an intermediate utility. In either case, OUC will charge for wheeling QF Firm Capacity and Energy pursuant to the provisions of OUC's Rate Schedule CG-3 for Transmission Service for a QF.

3. OUC shall be relieved of its obligation to purchase and pay for electric capacity and energy from a QF when purchases result in higher costs to OUC than without such purchases, and where service to OUC's other customers may be impaired by such purchases. On such occasions OUC shall notify the QF as soon as possible or practical.

Appendix A

METHODOLOGY FOR CALCULATING FIRM CAPACITY RATES

AVAILABILITY:

Appendix A provides a detailed description of the methodology used by Orlando Utilities Commission (OUC) to calculate the monthly values of deferring OUC's Avoided Resource referred to in Rate Schedule CG-2. Also contained in this appendix is the methodology used by OUC to calculate the 12-month rolling average capacity factors of a Qualifying Facility ("QF").

CALCULATION OF VALUE OF DEFERRAL:

OUC specifies that avoided capacity costs, in dollars per kilowatt per month, associated with firm capacity sold to OUC by a QF pursuant to OUC's standard offer shall be defined as the value of a year-by-year deferral of OUC's Avoided Resource and shall be calculated as follows:

$$VAC = CKI_n \left[\frac{1 - \frac{(1 + ip)}{(1 + r)}}{1 - \frac{(1 + ip)^L}{(1 + r)^L}} \right] (1 + i_p)^n$$

$$VAOM = \frac{CO_n}{12} \left[\frac{(1 + i_o)}{(1 + r)} \right] (1 + i_o)^n$$

$$PWVAC = \frac{VAC}{(1 + r)^n}$$

$$P_L = \frac{F}{12} \left[\frac{r}{1-(1 + r)^{-L}} \right]$$

Continued on Sheet No. 7.041

Appendix A

Continued from Sheet No. 7.040

Where, for a one year deferral:

VAC = OUC's annual value of avoided capacity cost, on a non-levelized basis, in dollars per kilowatt per year.

VAOM = OUC's monthly value of avoided fixed operating and maintenance expense, in dollars per kilowatt per month.

PWVAC= Present value of the annual avoided capacity cost payments, beginning on January 1, 1997.

F = The cumulative present value on January 1, 1997 of annual avoided capacity cost payments on a non-levelized basis for L years, in dollars per kilowatt.

P_L OUC's monthly value of avoided capacity, in dollars per kilowatt per month on a levelized basis for L years, beginning on January 1, 1997.

C = 1.0 a constant risk multiplier equal to 0.8 for the purpose of OUC's standard offer agreement;

K = present value of carrying charges for one dollar of investment over L years with carrying charges assumed to be paid at the end of each year;
LPN of KR

I_n = total direct and indirect installed cost, in dollars per kilowatt of OUC's Avoided Resource with an in-service date of year n;

O_n = total first year's fixed operating and maintenance expense, in dollars per kilowatt per year, of OUC's Avoided Resource.

i_o = annual escalation rate associated with the operation and maintenance expense of OUC's Avoided Resource.

i_p = 1.05 annual escalation rate associated with the capital cost of OUC's Avoided Resource;

r = 7.25 annual discount rate, defined as OUC's incremental cost of capital;

L = expected life of OUC's Avoided Resource; and

n = year for which OUC's Avoided Resource is deferred starting with its original designated in-service date and continuing for L years.

Normally, payment for firm capacity shall not commence until the in-service date of OUC's Avoided Resource. At the option of the QF, however, OUC may begin making early monthly capacity payments consisting of the capital cost component of the value of a year-by-year deferral of OUC's Avoided Resource starting as early as seventy (70) months prior to the designated in-service date of OUC's Avoided Resource. Such early monthly capacity payments shall be calculated as follows:

Continued on Sheet No. 7.042

Appendix A

Continued from Sheet No. 7.041

$$PWVAC = \frac{VAC}{(1 + r)^{m}}$$

$$P_L = \frac{F}{12}\left[\frac{r}{1-(1 + r)^{-L}}\right]$$

Where:

PWVAC= Present value of the annual avoided capacity cost payments, beginning with January 1st of the year in which early capacity payments to a QF begin

P_L = OUC's monthly value of avoided capacity cost, in dollars per kilowatt per month on a levelized basis for L years, beginning on January 1st of the year in which early capacity payments to a QF begin.

m = The number of years in advance of the designated in-service date of OUC's Avoided Resource that early payments will begin.

F = The cumulative present value in the year that contractual payments will begin, of the annual avoided capacity payments, on a non-levelized basis, which would have been made had capacity payments commenced with the designated in-service date of OUC's Avoided Resource (This value excludes the fixed operating and maintenance expense component).

Continued on Sheet No. 7.043

Appendix A

Continued from Sheet No. 7.042

The applicable parameters for the formulas above are as follows:

NORMAL PAYMENT OPTION PARAMETERS

For a one year deferral:

Parameter	Description	Value
VAC =	OUC's annual value of avoided capacity cost, in dollars per kilowatt per year, for the year 1997;	45.740
PWVAC=	Present value of the first year's annual avoided capacity cost payment;	45.740
F =	Cumulative present value of annual avoided capacity cost payments on a non-levelized basis for 40 years, in dollars per kilowatt;	1,134.963
P_L =	OUC's monthly value of avoided capacity on a levelized basis, in dollars per kilowatt per month, beginning on January 1, 1997;	8.488
VAOM =	First year's monthly value of avoided fixed operating and maintenance expense, in dollars per kilowatt per month;	1.544
C =	a constant risk multiplier for the purpose of OUC's standard contract offer;	0.8
K =	present value of carrying charges for one dollar of investment over L years with carrying charges assumed to be paid at the end of each year;	1.179
I_n =	total direct and indirect installed cost, in dollars per kilowatt of OUC's Avoided Resource with an in-service date of year n;	1,186
O_n =	total first year's fixed operating and maintenance expense, in dollars per kilowatt per year, of OUC's Avoided Resource;	23.83
i_p =	annual escalation rate associated with the capital cost of OUC's Avoided Resource;	5.67%

Continued on Sheet No. 7.044

ORLANDO UTILITIES COMMISSION ORIGINAL SHEET NO. 7.044

CG-2

Appendix A

Continued from Sheet No. 7.043

For a one year deferral:		Value
i_o =	annual escalation rate associated with the operation and maintenance expense of OUC's Avoided Resource;	5.61%
r =	annual discount rate, defined as OUC's incremental cost of capital;	8.65%
L =	expected life of OUC's Avoided Resource;	40 years
n =	year for which OUC's Avoided Resource is deferred starting with its original designated in-service date;	January 1, 1997

EARLY PAYMENT OPTION PARAMETERS:

For a one year deferral:		Value
VAC =	OUC's annual value of avoided capacity cost, in dollars per kilowatt per year, for the year 1997;	45.740
PWVAC=	Present value of the first year's annual avoided capacity cost payment, at January 1, 1990;	25.591
F =	Cumulative present value of annual avoided capacity cost payments on a non-levelized basis for 40 years, at January 1, 1990, in dollars per kilowatt;	634.709
P_L =	OUC's monthly value of avoided capacity cost, in dollars per kilowatt per month on a levelized basis, beginning on January 1, 1990;	4.747
m =	the number of years in advance of the designated in-service date of OUC's Avoided Resource that early payments will begin;	7 years

Continued on Sheet No. 7.045

TRANSMISSION SERVICE FOR A QUALIFYING FACILITY
RATE SCHEDULE CG-3

AVAILABILITY:

Transmission service hereunder is available over Orlando Utilities Commission (OUC) facilities to or from existing points of delivery and such other points as may be established on OUC's system. Firm and nonfirm transmission service is available where and so long as OUC's facilities have adequate capacity to permit the transmission requested by the Qualifying Facility ("QF") on a technically feasible basis without adversely affecting the adequacy, reliability, or cost of providing electric service to OUC's retail and other customers.

Firm Transmission Service

Firm transmission service for Firm Capacity and Energy shall be provided on a continuous basis for a specified quantity of power to be transmitted for the duration of an agreed upon commitment period so long as there is sufficient unused capacity in OUC's transmission facilities to provide such service.

A Letter of Commitment shall be required between the QF and OUC specifying the quantity of power to be transmitted (the "Contract Demand") and the period of time for which such deliveries are requested. Prior to entering into such Letter of Commitment, OUC may perform or may have performed, at the expense of the QF, load flow and stability studies of its system to determine whether or not the requested service will adversely affect the adequacy, reliability, or cost of providing electric service to OUC's retail and other customers. If the requested transmission service would require OUC to install new facilities, would cause it to install facilities significantly earlier than it would otherwise do, or otherwise cause it to incur exceptional expense, OUC reserves the right to decline to provide service under this tariff and, at its option, may offer transmission service under a compensatory contract. Such compensatory contract would, to the extent appropriate in the circumstances, follow the provisions of this transmission service tariff and its associated terms and conditions.

Non-Firm Transmission Service

Non-firm transmission service for As-Available Energy shall be provided on a when-, as-, and if-available basis and such service is interruptible at the sole option of OUC. OUC will provide notification of interruptions of non-firm transmission service at least one hour prior to such interruption, to the extent possible. Such service shall be provided only if there is sufficient unused capacity in OUC's transmission facilities.

Continued on Sheet No. 7.060

Continued from Sheet No. 7.060

In the event the QF fails to interrupt or curtail its use of Non-firm transmission service within one hour upon notification to so do by OUC, then such service shall, for billing purposes only, be considered as Firm transmission service and billed as such by OUC for the current and succeeding eleven billing months, but shall in all other respects still be considered as Non-firm transmission service. Non-firm transmission service is not available for transmission of Firm Capacity and Energy.

APPLICABILITY:

This Rate Schedule shall apply to transmission service for any QF to which OUC is directly or indirectly electrically interconnected for delivery of power generated by the QF to another electric utility. For purposes of this Rate Schedule, QF means a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Federal Energy Regulatory Commission's regulations under the Public Utilities Regulatory Policies Act of 1978, S201, with regard to cogeneration and small power production.

Service under this Rate Schedule is not available for the transmission of electrical power generated by the QF at one location to the facilities of the QF at another location or for transmission to any entity that is not an electric utility.

CHARACTER OF SERVICE:

The service under this Rate Schedule is 60 hertz, alternating current of the phase and nominal voltage desired by the QF, provided that the electric service of the voltage desired by the QF is available in the area in which service is desired.

Continued on Sheet No. 7.062

Continued from Sheet No. 7.061

LIMITATION OF SERVICE:

For both Firm and Nonfirm transmission service provided hereunder, OUC maintains the right at any time to deny, curtail, or discontinue transmission service (1) for interruptions or reductions due to force majeure; (2) for interruptions or reductions due to action instituted by automatic or manual control resulting in disconnection for the purpose of maintaining overall reliability and continuity of OUC's electric system or for the purpose of protecting OUC's generation or transmission or distribution facilities; (3) for temporary interruptions or reductions which, in the opinion of OUC, are necessary or desirable for the purpose of maintenance, repairs, replacements, or installation of equipment, or investigation and inspection; or (4) if OUC determines that the provision of such service would adversely affect the adequacy, reliability, or cost of providing electric service to OUC's retail or other customers.

Prior to initiating transmission service under this Rate Schedule, should the QF be located within OUC's electric system, OUC and the QF shall have executed a Parallel Operation Agreement covering the interconnected operations of OUC's and the QF's resources. Such agreement shall include, but not be limited to, the following topics:

a) Costs of interconnecting with the QF including specifically assigned costs to be paid by the QF, and any additional administrative and general expenses incurred by OUC to be paid by the QF,

b) Safety and Technical Standards for Parallel Operation,

c) Automatic and manual disconnection requirements,

d) Output compatibility,

e) Inadvertent energy flows,

f) Protective equipment requirements,

g) Metering provisions, including type, ownership, location, access and testing,

h) Indemnification, force majeure, insurance, and term, and

Continued on Sheet No. 7.063

Continued from Sheet No. 7.062

i) Reactive power penalty clause.

Prior to initiating transmission service under this Rate Schedule, if a QF is not located within OUC's electric system and requires transmission service over OUC's electric system, the QF shall provide OUC a copy of all executed agreements required to transmit capacity and energy from the QF's generating facilities to and from OUC's electric system and execute an agreement with OUC addressing the above listed items as appropriate.

TRANSMISSION RATES:

Firm and Non-firm transmission rates shall be based on OUC's projected revenue requirements associated with providing transmission service.

LOSSES:

OUC shall receive power from the QF for delivery and shall deliver at OUC's interconnection points with other utilities such amount received less an amount attributable to losses. These losses will be based on OUC's most recent annual data for the applicable system average loss percentage factor. If, in OUC's judgment, the use of average losses would not result in equitable compensation for losses incurred, incremental losses attributed to the transaction may be used. When incremental losses are to be used, the QF shall be so advised at least 30 days prior to the transaction.

VOLTAGE LEVEL ADJUSTMENTS

Transmission rates developed under this Rate Schedule shall be calculated to account for voltage level adjustments, if any.

Continued on Sheet No. 7.064

Continued from Sheet No. 7.063

DETERMINATION OF BILLING DEMAND:

Monthly charges for Firm transmission service shall be based on the monthly rate per kW multiplied by the Contract Demand in kW established in the Letter of Commitment. Monthly charges for Non-firm transmission service shall be based on the rate per kWh multiplied by the energy scheduled to be received by OUC and to be transmitted over OUC's system for the month.

TERMS OF PAYMENT:

Bills for transmission service shall be rendered monthly by OUC to the QF. All such bills shall be due and payable within ten (10) days from the date of mailing. Any amount due and unpaid after the due date shall be termed delinquent and there shall be added interest of one percent (1%) per month and an additional one percent (1%) for each month thereafter.

POWER FACTOR:

It shall be the responsibility of the QF receiving transmission services to supply enough reactive power to maintain the power factor of transmitted power as near unity as practicable.

SCHEDULED DELIVERIES:

It shall be the responsibility of the QF to arrange a schedule satisfactory to OUC for transmitted power and energy, up to the level of the Contract Demand, and to notify OUC of such schedule prior to commencement of the transaction. The QF shall furnish OUC a 24-hour schedule by noon of the prior day. The amount scheduled to be delivered will be rounded to the nearest whole MW for dispatching purposes only.

CONTINUITY OF TRANSMISSION SERVICE:

OUC does not guarantee that the transmission service delivered hereunder will be free from interruption or impairment, and OUC shall not be liable for damages resulting therefrom.

NO DEDICATION OF FACILITIES:

Any undertaking by one party to the other party under any provision of this Rate Schedule shall not constitute the dedication of the system or any portion thereof, of any party to the public or to the other party, and it is understood and agreed that any such undertaking by any party shall cease upon termination of this Rate Schedule.

Continued on Sheet No. 7.065

Continued from Sheet No. 7.064

TRANSMISSION BY THIRD PARTIES AND BACKUP GENERATION SERVICES:

The QF is responsible for all necessary transmission arrangements with any third parties and for backup generation services and shall also be responsible for all costs associated with transmission by other parties and for backup generation services.

CHANGES IN RATE SCHEDULE:

OUC may change the provisions of this transmission Rate Schedule, including the rates and associated terms and conditions, by notifying the QF in writing of such changes at least sixty (60) days in advance.

NOTICE

Any notice, demand or request required or authorized by this Rate Schedule shall be deemed properly given if mailed, postage prepaid to:

a. Notice to OUC from QF:

Orlando Utilities Commission, P.O. Box 3193, Orlando, Florida 32802; Attention: Director, System Operations, Electrical Operations Department. Such notice, demand or request must then be acknowledged and consented to by OUC in writing, or by phone call by Director, System Operations, or his designee.

b. Notice to QF from OUC:

____

Such notice, demand or request must then be acknowledged and consented to by __________ in writing, or by phone call by ___________, or his designee.

The designation of the person to be notified or the address of such person may be changed at any time, or from time to time by similar notice.

SOC-1

STANDARD OFFER CONTRACT FOR THE PURCHASE OF
AS-AVAILABLE ENERGY FROM A QUALIFYING FACILITY

THIS AGREEMENT is made and entered into this _________ day of ____________________, 19___ by and between the ____________________, (hereinafter referred to as the "QF") and Orlando Utilities Commission, (hereinafter referred to as the "OUC"), a statutory commission existing under the laws of the State of Florida. The QF and OUC shall collectively be referred hereinafter as the "Parties."

WITNESSETH:

WHEREAS, QF, being certified as such, desires to sell, and OUC desires to purchase, non-firm electricity to be generated by the QF consistent with the definitions and criteria contained in the Federal Energy Regulatory Commission Rules 292.101 and 292.301 through 292.308, effective March 20, 1980, and

WHEREAS, QF has signed a Parallel Operation Agreement with the electric utility (including OUC) in whose service territory the QF's generating facility is located, which is attached hereto as Appendix ________; and

WHEREAS, for a QF not directly interconnected with OUC's electric system, the QF has entered into the necessary agreements required to have the capacity and energy delivered to OUC's electric system, which is attached hereto as Appendix ____;

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

Continued on Sheet No. 7.081

Continued from Sheet No. 7.080

Section 1. Facility

QF has installed or operates or contemplates installing and operating a ____________________ kVA _______ generating facility located at ____________________. The generator is designed to produce a maximum of ____________ megawatts (MW), or __________ kilowatts (kW) of electric power at an 85% lagging power factor [90% leading for induction generators], such equipment being hereinafter referred to as the "Facility."

Section 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 , or until terminated by written notice by either Party.

Section 3. Sale of Electricity by QF

OUC agrees to purchase electric power generated by the QF and transmitted to OUC by QF as metered at the point of interconnection and, when applicable, adjusted for losses to the appropriate location on OUC's electric system.

OUC will make reasonable provisions to purchase As-Available Energy from the QF, but OUC will not make or accept such purchases of As-Available Energy from the QF to the extent such energy will jeopardize the integrity and/or reliability of OUC's system.

Section 4. Payment for Electricity Produced by QF

4.1 Energy. OUC agrees to pay for energy produced by the QF and delivered to OUC in accordance with the rates and procedures contained in Rate Schedule CG-1, and as may be amended from time to time.

Continued on Sheet No. 7.082

Continued from Sheet No. 7.081

<u>Section 5</u>. <u>Electricity Production Schedule</u>

During the term of this Agreement, QF agrees at its cost to:

(a) Comply with reasonable requirements of OUC regarding day-to-day and hour-by-hour communications between the parties relative to the performance of this Agreement;

(b) Provide all necessary information, including but not limited to data acquisition for real time telemetry and monitoring of actual generation output of the Facility, requested by OUC to implement and administer this Agreement and applicable rate schedules;

(c) Adjust reactive power flow in the interconnection as may be reasonably required by OUC or the electric utility with which the QF has signed a Parallel Operation Agreement within the range of 90% leading to 85% lagging power factor unless otherwise provided in the Parallel Operation Agreement;

(d) Come off line quickly during emergencies where generation from the Facility would contribute to the overloading of the interconnected utility system; and

(e) Provide any additional criteria reasonably required by OUC related to the delivery of As-Available energy by the QF.

Continued on Sheet No. 7.083

Continued from Sheet No. 7.082

Section 6. General Provisions

6.1 Permits. QF hereby agrees 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. OUC hereby agrees, at QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications or other authority OUC is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

6.2 Indemnification. QF agrees to indemnify and save harmless OUC and its respective employees, officers, directors, and agents against any and all liability, loss, damage, costs or expense which OUC and its respective employees, officers, directors, and agents may hereafter incur, suffer or be required to pay by reason of negligence on the part of QF in performing its obligations pursuant to this Agreement or QF's failure to abide by the provisions of this Agreement. To the extent permitted by law, OUC agrees to indemnify and save harmless the QF against any and all liability, loss, damage, cost or expense which QF may hereafter incur, suffer, or be required to pay by reason of the finding of an act of negligence on OUC's system committed by OUC in performing its obligations pursuant to this Agreement or OUC's failure to abide by the provisions of this Agreement. QF agrees to include OUC as an additional insured in any liability insurance policy or policies QF obtains to protect QF's interest with respect to QF's indemnity and hold harmless assurances to OUC contained in this Section.

Continued on Sheet No. 7.084

Continued from Sheet No. 7.083

6.3 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 causes not within the reasonable control of the Parties affected, including but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure 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 OUC's electric 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 OUC. OUC agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by OUC or its agents.

6.4 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 OUC's prior written approval.

6.5 Disclaimer. In executing this Agreement, OUC 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.

Continued on Sheet No. 7.085

Continued from Sheet No. 7.084

6.6 Notification. For purposes of making any and all nonemergency oral and written notices, payments 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 the QF:

____

____

____________________________ Phone ______________________

For OUC:

____

____

____________________________ Phone ______________________

6.7 Tax Exemption. OUC shall not be required to take any action under this Agreement if such action, in the opinion of OUC, would have an adverse effect on the tax-exempt status of OUC's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

6.8 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida and any unresolved disputes if litigated, shall be filed with the appropriate Florida courts.

Continued on Sheet No. 7.086

nt, for any reason, be
thority of appropriate
: the validity of the
l remain in force and
ithout the invalid or

All previous communi-
er verbal or written,
Agreement are hereby
is Agreement shall be
l duly executed by both

arties agree that this
ons contained in OUC's
ded from time to time.
e.

as may be amended from
enefit of the Parties'
entatives.

this Agreement the day

Facility

____
orized Officer

ilities Commission

____

SOC-2

STANDARD OFFER CONTRACT FOR THE PURCHASE OF
FIRM CAPACITY AND ENERGY FROM A QUALIFYING FACILITY

THIS AGREEMENT is made and entered into this ____________ day of ______________, 19__ by and between ______________________________ the Qualifying Facility, (hereinafter referred to as the "QF") and Orlando Utilities Commission (hereinafter referred to as the "OUC"), a statutory commission existing under the laws of the State of Florida. The QF and OUC shall collectively be referred hereinafter as the "Parties".

WITNESSETH:

WHEREAS, QF, being certified as such, desires to sell, and OUC desires to purchase, firm electricity to be generated by the QF consistent with the definitions and criteria contained in the Federal Energy Regulatory Commission Rules 292.101 and 292.301 through 292.308, effective March 20, 1980, and

WHEREAS, QF has signed a Parallel Operation Agreement with the electric utility (including OUC) in whose service territory the QF's generating facility is located, which is attached hereto as Appendix _________ and

WHEREAS, for a QF not directly interconnected with OUC's electric system, the QF has entered into the necessary agreements required to have the capacity and energy delivered to OUC's electric system, which is attached hereto as Appendix ____;

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

Continued on Sheet No. 7.101

Continued from Sheet No. 7.100

Section 1. Facility

QF has installed or operates or contemplates installing and operating a ______________________ kVA _______ generating facility located at _________________________. The generator is designed to produce a maximum of ______________ megawatts (MW), or__________ kilowatts (kW) of electric power at an 85% lagging power factor [90% leading for induction generators], such equipment being hereinafter referred to as the "Facility."

Section 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__.

If construction and commercial operation of the Facility are not accomplished by QF before January 1, 1995 (which date shall be at least two years prior to designated in-service date of OUC's Avoided Resource), this Agreement shall be rendered of no force and effect and OUC shall be entitled to take any remedies available to it in accordance with Florida law.

Notwithstanding the foregoing, in order to receive capacity payments pursuant to Section 4.2 or Section 6 herein, in consideration of the planning horizon for adding base load resources, this Agreement must be executed by both Parties at least seventy (70) months prior to the designated in-service date of OUC's Avoided Resource.

Section 3. Sale of Electricity by QF

OUC agrees to purchase electric power generated at the Facility and transmitted to OUC by QF as metered at the point of interconnection and, when applicable, adjusted for losses to the appropriate location on OUC's electric system.

Continued on Sheet No. 7.102

Continued from Sheet No. 7.101

Section 4. Payment for Electricity Produced by OF

4.1 Energy. OUC agrees to pay the QF for energy produced by the Facility and delivered to OUC in accordance with the rates and procedures contained in Rate Schedule CG-2 and as may be amended from time to time.

Prior to January 1, 1997, (designated in-service date of OUC's Avoided Resource) QF will receive energy payments based on OUC's actual hourly avoided energy costs. Beginning January 1, 1997, (designated in-service date of OUC's Avoided Resource) QF's energy payments will be based on the lesser of OUC's actual avoided hourly energy costs or the fuel costs of OUC's Avoided Resource as defined in Rate Schedule CG-2, with such comparison to be made hourly.

4.2 Capacity.

4.2.1 Anticipated Committed Capacity. QF expects to sell approximately __________ kW of capacity, beginning on or about ________________ 19__.

QF may finalize its Anticipated Committed Capacity after initial facility testing, and specify when capacity payments are to begin, by completing Section 4.2.2 at a later time. QF must complete Paragraph 4.2.2 by January 1, 1995, which date must be at least two years prior to the designated in-service date of OUC's Avoided Resource in order to be entitled to any capacity payments pursuant to this Agreement.

4.2.2 Actual Committed Capacity. The Actual Committed Capacity by QF for the purposes of this Agreement is ____________ kW and shall not deviate from the Anticipated Committed Capacity by the greater of one MW or 10% of the Anticipated Committed Capacity. QF elects to receive, and OUC agrees to commence calculating capacity payments in accordance with this Agreement starting with the first billing month following ______________, 19__.

Continued on Sheet No. 7.103

Continued from Sheet No. 7.102

4.2.3 Capacity Payments. QF chooses to receive capacity payments from OUC under Option ____________ (one of the options identified in Rate Schedule CG-2).

At the end of each billing month, beginning with the billing month specified in Section 4.2.2 and ending with the date specified in Section 3, OUC will calculate the most recent twelve-month rolling average capacity factors as established in Section 7 for such month based on QF's Actual Committed Capacity. During the initial twelve month period, this calculation will be based on the months that have transpired since the first billing month. If the capacity factors thus calculated are 70% or more for total hours and 85% or more for on-peak hours, then OUC 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 OUC to QF as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

Notwithstanding the foregoing, no capacity payments shall be made if the QF fails to comply with the provisions of Section 7 herein.

Section 5. Electricity Production Schedule

During the term of this Agreement, QF agrees at its cost to:

(a) Provide OUC by March 1 preceding each fiscal year (October 1 through September 30) or at other times as may be requested, an estimate of the amount of electricity to be generated by the Facility and delivered to OUC for each month of the fiscal 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) Coordinate the delivery of its generation output and its scheduled Facility outages with OUC and other utilities as appropriate;

Continued on Sheet No. 7.104

Continued from Sheet No. 7.103

(d) Comply with reasonable requirements of OUC regarding day-to-day and hour-by-hour communications between the parties relative to the performance of this Agreement;

(e) Provide all necessary information, including but not limited to data acquisition for real time telemetry and monitoring of actual generation output of the Facility, requested by OUC to implement and administer this Agreement and applicable rate schedules; and

(f) Adjust reactive power flow in the interconnection as may be reasonably required by OUC or the electric utility with which the QF has signed a Parallel Operation Agreement within the range of 90% leading to 85% lagging power factor unless otherwise provided in the Parallel Operation Agreement.

(g) Come off line quickly during emergencies where generation from the facility would contribute to the overloading of the interconnected utility system.

<u>Section 6</u>. <u>QF's Obligation if QF Receives Early Capacity Payments</u>

The QF's payment option choice pursuant to Section 4.2.3 may result in early payment by OUC for capacity delivered. The parties recognize that such capacity payments paid prior to January 1, 1997, (designated in-service date of OUC's Avoided Resource) are in the nature of Early Payments" for a future capacity benefit to OUC. To ensure that OUC will receive a capacity benefit for which early 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:

OUC shall establish a Capacity Account. Amounts shall be credited to the Capacity Account each month prior to January 1, 1997, (designated in-service date of OUC's Avoided Resource) equal to the amount of OUC's capacity payments made to the QF pursuant to QF's chosen payment option from Rate Schedule CG-2. The monthly balance in the Capacity Account shall accrue interest at an annual rate of ________% (equal to the annual discount rate used in developing the early payment to QF).

Continued on Sheet No. 7.105

Continued from Sheet No. 7.104

Commencing on January 1, 1997, (designated in-service date of OUC's Avoided Resource) there shall be debited from the Capacity Account each month 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 OUC would have paid for capacity in that month if the QF had elected to begin receiving payment on January 1, 1997, (designated in-service date of OUC's Avoided Resource) minus the monthly capacity payment OUC makes to QF pursuant to the capacity payment option chosen by QF in Section 4.2.3.

The QF shall owe OUC and be liable for the outstanding balance in the Capacity Account. OUC agrees to notify QF monthly as to the current Capacity Account balance. Prior to receipt of early capacity payments the QF shall provide a document promising to repay any outstanding balance in the Capacity Account in the event the QF defaults pursuant to this Agreement. Such promise shall be secured by means acceptable to OUC and in accordance with the provisions of Rate Schedule CG-2. The specific repayment assurance for purposes of this Agreement shall be: ____. The total outstanding balance in the Capacity Account shall immediately become due and payable in the event of a default by the QF, as defined pursuant to Section 9. The QF's obligation to pay the outstanding balance in the Capacity Account shall survive termination of this Agreement.

<u>Section 7. Performance Criteria</u>

A QF, in order to be eligible to receive firm energy and capacity payments, must comply with the following minimum performance criteria:

(i) The QF will begin to deliver energy and capacity no later than two years prior to January 1, 1997, (the designated in-service date of OUC's Avoided Resource) and continuing for a period of at least ten years beyond such designated date;

Continued on Sheet No. 7.106

Continued from Sheet No. 7.105

(ii) The QF agrees to maintain a minimum seventy percent (70%) capacity factor for energy delivered by the QF on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours as defined in Rate Schedule CG-2 during the period, and such calculations shall exclude amounts of hourly output (energy) in excess of 5% above the Actual Committed Capacity;

(iii) The QF agrees to provide monthly generation estimates by March 1 for the next fiscal year;

(iv) The QF agrees to promptly update the yearly generation schedule when any changes are determined necessary;

(v) The QF agrees to reduce generation or take other appropriate action as requested by OUC for safety reasons or to preserve system integrity;

(vi) The QF agrees to coordinate the delivery of its generated output and scheduled outages with OUC and other utilities as appropriate;

(vii) The QF agrees to comply with OUC's reasonable requests regarding daily or hourly information and communications requirements;

(viii) The QF agrees that it is not entitled to receive capacity payments until the QF has attained commercial in-service status. The commercial in-service date of the QF is defined as the first day of the month following the successful completion of the QF maintaining an hourly kilowatt output, as metered at the point of interconnection with OUC equal to or greater than the QF's Actual Committed Capacity for a 24-hour test period;

(ix) The QF agrees to coordinate the selection of the above described test period and operation of its facility during such test period with OUC in order to ensure that the performance of the QF during the 24-hour test period is reflective of the anticipated day-to-day operation of the QF;

(x) The QF agrees that the maximum hourly output of its facility shall not exceed the Actual Committed Capacity as defined in Section 4.2.2 by more than 5%;

Continued on Sheet No. 7.107

Continued from Sheet No. 7.106

(xi) The QF agrees that the Facility will be able during emergencies to perform as follows: (a) quickly coming on line, (b) quickly adjusting generation output, (c) remaining in operation and connected to the interconnected utility system, and (d) quickly coming off line where generation from the Facility would contribute to the overloading of the interconnected utility system;

(xii) The QF agrees, since fuel supply is a major factor in the delivery of a reliable supply of capacity and energy from the Facility, to maintain an adequate and reliable supply of primary fuel during the term of this agreement with backup fuel storage or supplementary fuel supply as deemed appropriate and provide pertinent information, including contract documents, upon request by OUC;

(xiii) The QF agrees to any additional criteria reasonably required by OUC related to the delivery of firm energy and capacity by the QF during OUC's daily and seasonal peak periods; and

(xiv) If the QF's continued operation depends on the sale of thermal energy, the QF agrees to maintain contracts for sale of such during the term of this agreement and agrees to provide pertinent information, including contract documents, upon request by OUC.

Section 8. Failure to Meet Performance Criteria

8.1 The QF's failure to meet the Performance Criteria in any month where normal capacity payments have been selected will result in no capacity payment by OUC to the QF for such month.

8.2 Where early capacity payments have been selected, for those months prior to the designated in-service date of OUC's Avoided Resource in which the QF does not meet the Performance Criteria, the QF will receive no capacity payment. Commencing with the designated in-service date of OUC's Avoided Resource, the QF will not only fail to receive a capacity payment, but must also immediately repay to OUC the difference between what it would have been paid had it elected the normal payment option and what it would have been paid pursuant to the early payment option had it met the Performance Criteria.

Section 9. Default

9.1 Should any of the following conditions exist, OUC shall have the right to declare the QF in default under this Agreement:

(i) The QF ceases all electric generation for twelve (12) consecutive months;

Continued on Sheet No. 7.108

Continued from Sheet No. 7.107

(ii) After _______________, 19__, (month in which capacity payments commence) the QF fails to maintain a 70% capacity factor on a twelve-month rolling average basis for total hours or fails to maintain an 85% capacity factor on a twelve-month rolling average basis for on-peak hours, for twenty-four consecutive months;

(iii) The QF ceases the conduct of active business; or if proceedings under the Bankruptcy Act or insolvency laws shall be instituted by or for or against QF; or if a receiver shall be appointed for the QF or any of its assets or properties; or if any part of the QF shall be attached, levied upon, encumbered, pledged, seized, or taken under any judicial process and such proceedings shall not be vacated or fully stayed within thirty (30) days thereof; or if the QF shall make an assignment for the benefit of creditors or admit in writing its inability to pay its debts as they become due:

(iv) The QF fails to give proper assurance of adequate performance as specified under the Agreement within thirty (30) days after OUC, with reasonable grounds for insecurity, has requested in writing such assurance; and

(v) The QF materially fails to perform as specified under this Agreement.

Once this contract is declared to be in default, upon written notice to the QF then the current balance in the Capacity Account shall be paid to OUC.

9.2 The QF shall provide security to OUC for payment of the current balance, existing from time to time, of the Capacity Account in the event of default by the QF. Security shall be provided by furnishing a bond or by setting up an escrow account to receive payment of Early Capacity Payments. If a bond is furnished, it shall be written on a company and in a form acceptable to OUC. The bond shall be furnished at the time of execution of this Agreement by the QF and shall have an effective period coextensive with the terms of this contract. The minimum amount of the bond shall be equal to the balance in the Capacity Account as it may exist from time to time during the term of this Agreement.

If an escrow account is established, an escrow agreement will be executed by the parties in a form acceptable to OUC. Early Capacity Payments will be paid into an interest-bearing account and will be accumulated by the escrow agent until the designated in-service date of OUC's avoided resource. After that date, the escrow agent shall make monthly payments to the QF in amounts equal to the Early Capacity Payment Offset Amount calculated pursuant to Section 6 of this Agreement.

Continued on Sheet No. 7.109

Continued from Sheet No. 7.108

9.3 The parties agree that any default by the QF as defined in this Section will result in substantial injury to OUC but that a general amount for damages arising from such failures cannot be predetermined. Therefore, the parties agree that if the QF should default under the terms of this Section, the QF shall pay to OUC, as liquidated damages and not as a penalty, the amount of $__________, which is based on seventy (70) months of exposure for OUC and $1.00/kW-month of QF capacity stipulated in Section 4.2 of this contract. This provision shall in no way affect any right OUC might have to terminate this Agreement, and OUC's exercise of a right to terminate shall not release the QF from its obligation to pay liquidated damages in the amount set forth in this paragraph. The QF shall post a bond upon its execution of this Agreement in the amount of the liquidated damages set forth herein and in a form acceptable to OUC. Said bond shall secure payment of liquidated damages to OUC in the event of default by the QF.

Section 10. General Provisions

10.1 Permits. QF hereby agrees 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. OUC hereby agrees, at QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications or other authority OUC is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

10.2 Indemnification. QF agrees to indemnify and save harmless OUC and its respective employees, officers, directors, and agents against any and all liability, loss, damage, costs or expense which OUC and its respective employees, officers, directors, and agents may hereafter incur, suffer or be required to pay by reason of negligence on the part of QF in performing its obligations pursuant to this Agreement or QF's failure to abide by the provisions of this Agreement. To the extent permitted by law, OUC agrees to indemnify and save harmless the QF against any and all liability, loss, damage, cost or expense which QF may hereafter incur, suffer, or be required to pay by reason of the finding of an act of negligence on OUC's system committed by OUC in performing its obligations pursuant to this Agreement or OUC's failure to abide by the provisions of this Agreement. QF agrees to include OUC as an additional insured in any liability insurance policy or policies QF obtains to protect QF's interest with respect to QF's indemnity and hold harmless assurances to OUC contained in this Section.

Continued on Sheet No. 7.110

Continued from Sheet No. 7.109

10.3 Renegotiations Due to Regulatory Changes. Notwithstanding anything in this Agreement to the contrary, should OUC at any time during the term of this Agreement fail to obtain or be denied the regulatory authorization of any regulatory body which now has or in the future may have jurisdiction over OUC's rates and charges, 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 OUC's option, they shall renegotiate this Agreement or any applicable amendment. If OUC exercises such option to renegotiate, OUC shall not thereafter be required to make such payments to the extent OUC's authorization to recover them from its customers is not obtained or is denied. OUC'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 OUC's payment obligations under this Agreement or any amendment hereto are conditioned upon OUC's being fully reimbursed for such payments through its Energy Cost Adjustment Clause or other authorized rates or charges. Any amounts initially recovered by OUC from its ratepayers but for which recovery is subsequently disallowed by any regulatory body asserting jurisdiction and charged back to OUC may be set off or credited against subsequent payments made by OUC for purchases from the QF, or alternatively, shall be repaid by the QF.

Continued on Sheet No. 7.111

Continued from Sheet No. 7.110

10.4 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 causes not within the reasonable control of the Parties affected, including but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure 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 OUC's electric 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 OUC. OUC agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by OUC or its agents.

10.5 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 OUC's prior written approval.

10.6 Disclaimer. In executing this Agreement, OUC 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.

Continued on Sheet No. 7.112

Continued from Sheet No. 7.111

10.7 Notification. For purposes of making any and all nonemergency oral and written notices, payments 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 the QF:

____

____

__________________________ Phone ____________________

For OUC:

____

____

__________________________ Phone ____________________

10.8 Tax-Exemption. OUC shall not be required to take any action under this Agreement if such action, in the opinion of OUC, would have an adverse effect on the tax exempt status of OUC's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

10.9 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida and any unresolved disputes if litigated, shall be filed with the appropriate Florida courts.

Continued on Sheet No. 7.113

Continued from Sheet No. 7.112

10.10 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.

10.11 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.

10.12 Incorporation of Rate Schedule. The Parties agree that this Agreement shall be subject to all of the provisions contained in OUC's published Rate Schedule CG-2 as approved and amended from time to time. The Rate Schedule is incorporated herein by reference.

10.13 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 HEREOF, QF and OUC have executed this Agreement the day and year first above written.

Attested:	Qualifying Facility
By:______________________	By:______________________
	Authorized Officer
Attested:	
By:______________________	By:______________________

Approved as to form and correctness:

____

PARALLEL OPERATION AGREEMENT
WITH QUALIFYING FACILITY

Orlando Utilities Commission (OUC) agrees to interconnect and operate in parallel its electric system with the electric generating facility of ________________, Qualifying Facility ("QF") subject to the following provisions. The QF and OUC shall collectively be referred hereinafter as the "Parties."

1. **Facility**

The QF's generating facility, hereinafter referred to as the "Facility," is located at ____. QF intends to have its Facility installed and operational on or about ______________, 19__. QF shall provide OUC reasonable prior notice of the Facility's initial operation, and it shall cooperate with OUC to arrange initial deliveries of power to OUC's electric system.

The Facility has been or will be certified as a QF pursuant to Federal Energy Regulatory Commission Rules 202.201 through 292.207 effective March 20, 1980. The QF shall maintain this certification status throughout the term of this Agreement.

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__.

If construction and commercial operation of the Facility are not accomplished by QF before January 1, 1995 (which date shall be at least two years prior to designated in-service date of OUC's Avoided Resource), this Agreement shall be rendered of no force and effect and OUC shall be entitled to take any remedies available to it in accordance with Florida law.

3. **Construction Activities**

QF shall provide OUC with written instructions to proceed with construction of the interconnection facilities as described in this Agreement at least 36 months prior to the date on which the Facility shall be completed. OUC agrees to use its reasonable best efforts to complete the interconnection facilities as described in this Agreement within 36 months of receipt of written instructions to proceed.

Continued on Sheet No. 7.131

Continued from Sheet No. 7.130

Upon the Parties' agreement as to the appropriate interconnection design requirements and receipt of written instructions to proceed from the QF, OUC shall design and perform or cause to be designed and performed all of the work necessary to interconnect the Facility with OUC's electric system.

QF agrees to pay OUC all expenses incurred by OUC to design, construct, operate, maintain, repair, modify, improve and remove the interconnection with QF and OUC's electric system as required to integrate the QF's Facility into OUC's electric system. Such costs shall exclude any costs which OUC would otherwise incur if it were not engaged in interconnected operations with QF, but instead simply provided the electric power requirements of the QF with electricity either generated by OUC or purchased by OUC from another source.

In the event QF notifies OUC in writing to cease work required for the interconnection before its completion, QF shall be obligated for all costs incurred up to the date notification is received by OUC including contract cancellation costs.

4. Cost Estimates

Attached hereto as Exhibit A and incorporated herein by this reference, is a document entitled "QF Interconnection Cost Estimates." The Parties agree that the cost of the interconnection work contained in Exhibit A is only an estimate of the actual cost to be incurred. The estimated amount will be required to be deposited by the QF to OUC prior to commencement of work on the project. Actual close-out cost of the project may be higher or lower depending upon the completion of the project. To the extent the actual cost is less than the estimate, the difference will be reimbursed to the QF. Likewise, expenses greater than the estimate will be billed to the QF and shall be paid within twenty (20) days of receipt of the invoice.

5. Safety and Technical Requirements

The Parties agree that QF's interconnection and parallel operation with, and delivery of electricity into, OUC's electric system must be accomplished in accordance with the provisions of Exhibit B entitled "Safety and Technical Standard for Interconnection and Parallel Operation of a Qualifying Facility" attached hereto, and made a part of this Agreement.

Continued on Sheet No. 7.132

The interconnection facilities shall include the items identified in Exhibit C, Diagrams and Description of Interconnection Facility, which is made an integral part of this Agreement.

Interconnection facilities on OUC's side of the ownership point with QF shall be owned, operated, maintained, and repaired by OUC. QF shall be responsible for the cost of designing, installing, operating, maintaining, repairing, modifying, and improving the interconnection facilities on QF's side of the ownership point as indicated in Exhibit C. The QF shall be responsible for establishing and maintaining controlled access by third parties to the interconnection facilities.

7. <u>Maintenance and Repair Payments</u>

OUC will separately invoice QF monthly for all costs associated with the operation, maintenance, repair, modification, and improvement of the interconnection facilities. QF agrees to pay OUC within twenty (20) days of receipt of each such invoice.

8. <u>Site Access</u>

In order to help ensure the continuous, safe, reliable and compatible operation of the Facility with OUC's electric system, QF hereby grants OUC for the period of this Agreement the reasonable right of ingress and egress, consistent with the safe operation of the Facility, over property owned or controlled by QF to the extent OUC deems such ingress and egress necessary in order to examine, test, calibrate, coordinate, operate, maintain, repair, modify or improve any interconnection equipment involved in the parallel operation of the Facility and OUC's electric system, including OUC's metering equipment.

Continued on Sheet No. 7.133

Continued from Sheet No. 7.132

9. <u>No OUC Endorsement</u>

In no event shall any OUC statement, representation, or lack thereof, either expressed or implied, relieve the QF of its exclusive responsibility for the Facility. Specifically, any inspection by OUC or its agent(s) of the Facility shall not be construed as confirming or endorsing the Facility's design or its operating or maintenance procedures nor as a warranty or guarantee as to the safety, reliability, or durability of the Facility's equipment. OUC's inspection, acceptance, or its failure to inspect shall not be deemed an endorsement of any equipment or procedure of the QF.

10. <u>Responsibility and Liability</u>

OUC shall be responsible for OUC owned facilities. OUC shall indemnify and save the QF harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property by reason of negligence on the part of OUC in performing its obligations pursuant to the interconnection agreement. The QF shall be responsible for the QF's entire system, ensuring adequate safeguards for other utility customers, utility personnel and equipment, and for the protection of its own generating system. The QF shall indemnify and save OUC harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property (including the QF's generation system and OUC's system) caused by, arising out of, or resulting from:

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

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

3. The QF's negligence or negligence of QF's contractors, agents servants and employees or;

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

Continued on Sheet No. 7.134

Continued from Sheet No. 7.133

11. Insurance

QF shall deliver to OUC at least fifteen (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 OUC 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 conditions, or otherwise arising out of the performance by the QF or OUC of the terms and conditions of this Agreement.

The policy providing such coverage shall provide public liability insurance, including property damage, with limits in an amount to be determined on a case-by-case basis by OUC, but in no event less than $300,000 for each occurrence. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify OUC thirty (30) days prior to the effective date of cancellation or material change in policy. The QF shall pay all premiums and other charges due so that said policy shall remain in force during the entire period of the interconnection with OUC.

12. 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 causes not within the reasonable control of the Parties affected, including but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure if it is caused by the negligence or lack of due diligence on the part of the Party attempting

Continued on Sheet No. 7.135

Continued from Sheet No. 7.134

to make such claim. QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with OUC's electric 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 OUC. OUC agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by OUC or its agents.

13. <u>Electric Service to QF</u>

OUC 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 electricity to OUC.

14. <u>Permits</u>

QF hereby agrees 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. OUC hereby agrees, at QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications or other authority OUC is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

15. <u>Notification</u>

For purposes of communications required or authorized by this Agreement, the Parties designate the following representatives:

For the QF: ______________________________

____

______________________________ Phone: ________________

For OUC: ______________________________

____

______________________________ Phone: ________________

The designation of the above representatives and other pertinent information may be changed by either party at any time upon advance notice provided from one party to the other.

Continued on Sheet No. 7.136

Continued from Sheet No. 7.135

16. Tax-Exemption

OUC shall not be required to take any action under this Agreement if such action, in the opinion of OUC, would have an adverse effect on the tax exempt status of OUC's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

IN WITNESS WHEREOF, QF and OUC, executed this agreement this __________ day of __________, 19__.

WITNESS: For the QF:

______________________________ ______________________________

Date: ______________________________

ATTEST: For OUC:

______________________________ ______________________________

Date ______________________________

EXHIBIT A

QUALIFYING FACILITY INTERCONNECTION COST ESTIMATES

INTENTIONALLY LEFT BLANK

EXHIBIT C

DIAGRAMS AND DESCRIPTION OF INTERCONNECTION FACILITY

INTENTIONALLY LEFT BLANK

EXHIBIT B

SAFETY AND TECHNICAL STANDARDS FOR PARALLEL OPERATION OF A QUALIFYING FACILITY

INTENTIONALLY LEFT BLANK

INDEX OF CONTRACTS AND AGREEMENTS

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING FACILITY RATE SCHEDULE CG-1

AVAILABILITY:

This Rate Schedule is available throughout the entire service territory of the Kissimmee Utility Authority (KUA). KUA will purchase energy offered by any Qualifying Facility (QF) within the territory served by KUA under the provisions of this Rate Schedule or at contract negotiated rates. KUA will negotiate and may contract with a QF outside KUA's service territory where such negotiated contracts are, as determined by KUA, in the best interest of KUA.

APPLICATION:

This Rate Schedule is applicable to any QF producing energy for sale to KUA on an as-available basis pursuant to the terms and conditions of this Rate Schedule and KUA's Standard Offer Contract for the Purchase of As-Available Energy from a Qualifying Facility (SOC-1 Contract) or a separately negotiated contract. As-Available Energy is energy produced and sold by a QF on an hour-by-hour basis for which firm commitments as to the time, quantity, or reliability of delivery are not required. Criteria for achieving QF status shall be those set out in the Federal Energy Regulatory Commission Rules 292.201 through 292.207, effective March 20, 1980.

CHARACTER OF SERVICE:

Purchases within the territory served by KUA shall be, at the option of KUA, single or three-phase, 60 hertz, alternating current at standard available voltage. Purchases from outside the territory served by KUA shall be three phase, 60 hertz, alternating current at the voltage level available at the interchange point between KUA and the utility delivering As-Available Energy from the QF.

LIMITATION OF SERVICE:

Purchases under this Rate Schedule are subject to KUA's need for As-Available Energy. The need for As-Available Energy will be periodically determined by KUA on the basis of projected energy requirements and available resources. Service under this rate Schedule is limited to those QFs which execute a SOC-1 Contract with KUA.

RATES FOR PURCHASES BY KUA:

A. Capacity Rates
Capacity payments to QFs will not be paid under this schedule. Capacity payments to QFs may be obtained under Schedule CG-2, Firm Capacity and Energy from a QF.

B. Energy Rates
The energy rate in cents per kilowatt-hour (¢/kWh) shall be based on KUA's actual hourly avoided energy costs which are calculated by KUA. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for energy losses as appropriate.

The calculation of payments to the QF 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 purchases by KUA for that hour. All purchases from QF shall be adjusted for energy losses from the point of metering to the appropriate location on KUA's electric system.

C. Negotiated Rates
Upon agreement by both KUA and the QF, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

METERING REQUIREMENTS:

QFs within the territory served by KUA shall be required to pay all costs associated with meters and related facilities necessary to measure their energy production as delivered to KUA. Energy purchases from Qfs outside the territory served by KUA shall be measured as the quantities scheduled for interchange to KUA by the utility delivering As-Available Energy to KUA on behalf of the QF.

Hourly recording meters shall be required for QFs with an installed capacity of 100 kilowatts or more. Where the installed capacity is less than 100 kilowatts, the QF may select any one of the following options: (1) hourly recording meter, (2) dual kilowatt-hour register time-of-day meter, or (3) standard kilowatt-hour meter.

For QFs with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on: (1) KUA's actual avoided energy rate for each hour during the month; (2) the quantity of energy sold by the QF during that hour; and (3) energy losses.

For QFs with dual kilowatt-hour register time-of-day meters, monthly payments for As-Available Energy shall be calculated based on: (1) the average of KUA's actual hourly avoided energy rates for the on-peak and off-peak periods during the month; (2) the quantity of energy sold by the QF during on-peak and off-peak periods, respectively; and (3) energy losses.

For QFs with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of (1) the average of KUA's actual hourly avoided energy rate for the off-peak periods during the month; (2) the quantity of energy sold by the QF during the month; and (3) the appropriate delivery voltage adjustment factor.

For a time-of-day metered QF, 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., clock time. All hours not mentioned above and all hours of the holidays of New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

TERMS OF PAYMENT:

A statement covering the charges and payments due the QF shall be prepared and rendered monthly by KUA, and payment normally will be made by the twentieth business day following the end of the billing period.

CHARGES TO QUALIFYING FACILITY:

A. Charges for Additional Services
KUA shall charge and collect for additional services requested by the QF to be provided by KUA. Such charges and collections shall be in accordance with KUA's applicable rate schedule(s) which rate schedules by reference become a part of this Rate Schedule, and which rate schedule(s) may at KUA's option be revised from time to time.

B. Interconnection Charge for Nonvariable Utility Expenses
The QF shall bear the cost required for interconnection facilities, including the investment cost and operation and maintenance expenses of metering and related facilities, and interconnection facilities, directly assignable KUA system protection facilities, a prorata share of energy cost accounting and QF administrative expenses, and the costs associated with eliminating any impairment or reduction of the electric power transfer capability of KUA's transmission system, resulting from or attributable to the interconnection of the QF. Such costs and expenses shall not include KUA expenditures which would have been incurred by KUA in providing electric service to the QF under one of KUA's retail rate schedules.

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

TERMS OF SERVICE:

1. It shall be the QF's responsibility to inform KUA in advance of any change in its electric generation capability.

2. Any electric service delivered by KUA in advance to the QF 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 shall be required in accordance with KUA's rules and regulations and the following:

   A. In the first year of operation, the security deposit shall be based upon the singular month in which the QF's projected purchases from KUA exceed, by the greatest amount, KUA's estimated purchases from the QF. 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 QF and KUA 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 QF exceed the actual sales to KUA in that month.

4. KUA shall specify the point of interconnection and the voltage level.

5. KUA will, under the provisions of this Rate Schedule, require a Parallel Operation Agreement between the QF and the electric utility in whose service territory the QF's generating facility is located. The QF shall recognize that its generation facility located in KUA's service territory may exhibit unique interconnection requirements which will be separately evaluated by KUA, modifying KUA's safety and technical standards where applicable.

6. Service under this Rate Schedule is subject to the rules and regulations of KUA.

SPECIAL PROVISIONS:

1. Special contracts deviating from the above standard rate schedule are allowable provided they are agreed to by KUA.

2. A QF located within KUA's service territory may sell As-Available Energy to a utility other than KUA when adequate transmission capacity is available on KUA's system as determined by KUA. When such conditions exist, KUA will provide transmission wheeling service to deliver the QF's power to the purchasing utility or to an intermediate utility. In addition, KUA will provide transmission wheeling service through its service territory, when adequate transmission capacity exists as determined by KUA, for a QF located outside KUA's service territory, for delivery of the QF's power to the purchasing utility or to an intermediate utility. In either case, KUA will charge for wheeling QF

As-Available Energy pursuant to the provisions of KUA's Rate Schedule CG-3 for Transmission Service for a QF.

3. KUA shall be relieved of its obligation to purchase and pay for As-Available Energy from a QF when purchases result in higher costs to KUA than without such purchases, and where service to KUA's other customers may be impaired by such purchases. On such occasions, KUA shall notify the QF as soon as possible or practical.

STANDARD RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM QUALIFYING FACILITY RATE SCHEDULE CG-2

AVAILABILITY:

This Rate Schedule is available to Qualifying Facilities (QF) throughout the entire service territory of the Kissimmee Utility Authority (KUA). KUA will purchase Firm Capacity and Energy offered by any QF within the territory served by KUA under the provisions of this Rate Schedule or at contract negotiated rates and may contract for the purchase of Firm Capacity and Energy from a QF outside KUA's service territory where such purchases are, as determined by KUA, in the best interest of KUA.

APPLICATION:

This Rate Schedule is applicable to any QF, irrespective of its location, producing capacity and energy for sale to KUA on a firm basis pursuant to the terms and conditions of this Rate Schedule and KUA's Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility ("SOC-2 Contract"), or a separately negotiated contract. Firm Capacity and Energy are capacity and energy produced and sold by a QF pursuant to the SOC-2 Contract or a negotiated contract and subject to contractual provisions as to quantity, time, and reliability of delivery. Criteria for achieving QF status shall be those set out in the Federal Energy Regulatory Commission Rules 292.201 through 292.207, effective March 20, 1980.

CHARACTER OF SERVICE:

Purchases within the territory served by KUA shall be, at the option of KUA, single or three-phase, 60 hertz, alternating current at standard available voltage. Purchases from outside the territory served by KUA shall be three phase, 60 hertz, alternating current at the voltage level available at the interchange point between KUA and the utility delivering Firm Capacity and Energy from the QF.

LIMITATION OF SERVICE:

Purchases under this Rate Schedule are subject to KUA's need for Firm Capacity and Energy. The need for Firm Capacity, as determined by KUA, shall be equal to the allowable portion of firm capacity scheduled to be purchased under one or more contracts for supplemental resale service from one or more electric utilities ("Supplemental Resale Service"), or other amount as determined by KUA. Such portion of such firm capacity shall be determined by KUA in accordance with the provisions of such contracts regarding reductions in contract demands.

Service under this Rate Schedule is limited to those QFs which execute a SOC-2 Contract for the purchase of Firm Capacity and Energy by KUA.

RATES FOR PURCHASES BY KUA:

Firm Capacity and Energy are purchased at a unit cost, in dollars per kilowatt per month and cents per kilowatt hour, respectively, based on the value of replacing capacity resource(s) for KUA. For the purpose of this Rate Schedule, the Avoided Resource has been designated by KUA as Supplemental Resale Service.

A. Firm Capacity Rates

Payment schedules are based on the value of KUA's Avoided Resource.

Subject to approval by KUA, the QF shall select the month and year in which the delivery of Firm Capacity and Energy to KUA is to commence and capacity payments are to start. KUA will provide the QF 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. Such capacity rates shall not be greater than the capacity rates KUA would have paid under the Supplemental Resale Service for firm capacity as identified, if service under this rate schedule had not taken place.

B. Energy Rates

The energy rate in cents per kilowatt-hour (¢/kWh) shall be based on KUA's actual hourly avoided energy costs, as determined by KUA, which would have been incurred by KUA had KUA not purchased energy from the QF. Such avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, the cost of energy purchased from other utilities, and an adjustment for energy losses reflecting delivery to the appropriate location on KUA's electric system. When transactions with other utilities take place, the incremental costs are calculated after purchases from other utilities and before sales to other utilities.

The calculation of payments to the QF 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 purchases by KUA for that hour. All purchases from QF shall be adjusted for energy losses as appropriate. To the extent that KUA's Avoided Resource would have been operated, such avoided energy costs shall reflect the energy cost of the Avoided Resource as specified in Appendix A. To the extent that KUA's Avoided Resource would not have been operated, such avoided energy costs shall reflect KUA's As-Available Energy cost as specified in KUA Rate Schedule CG-1, Standard Rate for Purchase of As-Available Energy from a Qualifying Facility.

PERFORMANCE CRITERIA:

Payments for firm capacity are subject to the QF's ability to comply with and maintain the performance criteria set forth in the SOC-2 Contract and as follows:

A. Commercial In-Service Date

Capacity payments shall not commence until the QF has attained and demonstrated commercial in-service status. The commercial in-service date of the QF shall be defined as the first day of the month following the successful demonstration of the QF maintaining an hourly kilowatt (kW) output, as metered at the point of interconnection with KUA, equal to or greater than the QF's Actual Committed Capacity for a test period as set forth in the SOC-2 Contract. A QF shall coordinate the selection of the test period and operation of its facility during such test period with KUA to ensure that the performance of the QF during this test period is reflective of the anticipated operation of the QF.

B. Capacity Factor

Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly by KUA in accordance with the provisions for this Rate Schedule and associated contract and subject to the provision that the QF maintains a minimum seventy percent (70%) capacity factor on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours. Failure to achieve these capacity factors shall result in the QF's forfeiture of payments for Firm Capacity during the month in which such failure occurs.

C. Additional Criteria

1. Prior to an annual date specified by KUA, the QF shall provide to KUA for the next fiscal year or at other times requested by KUA, monthly generation estimates;
2. The QF shall promptly update its yearly generation schedule and maintenance schedule as and when any changes are determined necessary;
3. The QF shall agree to reduce generation or take other appropriate action as requested by KUA for safety reasons or to preserve system integrity;
4. The QF shall coordinate the delivery of its generated output and scheduled outages with KUA;
5. The QF shall comply with the reasonable requests of KUA regarding daily or hourly communications;

6. The QF shall provide all necessary information including, but not limited to data acquisition for real time telemetry and acquisition of actual generation output of the Facility, requested by KUA to implement and administer this Rate Schedule and other applicable rate schedule(s); and

7. The QF's maximum hourly output shall not exceed the Actual Committed Capacity defined in its Standard Offer Contract by more than five percent (5%).

8. The QF shall adjust reactive power flow in the interconnection utility with which the QF has signed a Parallel Operation Agreement within the range of ninety percent (90%) leading to eight-five percent (85%) lagging power factor unless otherwise provided in the Parallel Operation Agreement.

ENERGY LOSS ADJUSTMENTS:

Energy payments to QFs within KUA's service territory shall be adjusted to the appropriate location on KUA's electric system based on energy losses which would have been incurred if the QF energy had not be purchased by KUA.

METERING REQUIREMENTS:

QFs within the territory served by KUA shall be required to pay all costs associated with meters and related facilities necessary to measure their energy production. Energy purchases from QFs outside the territory served by KUA shall be measured as the quantities scheduled for interchange to KUA by the utility delivering Firm Capacity and Energy to KUA on behalf of the QF.

Hourly recording meters shall be required for all QFs delivering firm energy.

TERMS OF PAYMENT:

A statement covering the charges and payments due the QF shall be prepared and rendered monthly by KUA, and payment normally will be made by the twentieth business day following the end of the billing period.

CHARGES TO QUALIFYING FACILITY:

A. <u>Charges for Additional Services</u>
KUA shall charge and collect for additional services requested by the QF and provided by KUA. Such charges and collections shall be in accordance with KUA's applicable rate schedule(s) which rate schedules by reference become a part of this Rate Schedule, and which rate schedule(s) may at KUA's option be revised from time to time.

B. Interconnection Charge for Nonvariable Utility Expenses
The QF shall bear the cost required for interconnection facilities, including the investment cost and operation and maintenance expenses of metering and related facilities, and interconnection facilities directly assignable to the KUA system protection facilities, a prorata share of energy cost accounting and QF administrative expenses, and the costs associated with eliminating any impairment or reduction of the electric power transfer capability of KUA's transmission system, resulting from or attributable to the interconnection of the QF. Such costs and expenses shall not include KUA expenditures which would have been incurred by KUA in providing electric service to the QF under one of KUA's retail rate schedules.

C. Taxes and Assessments
The QF shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which KUA is liable as a result of its purchases of Firm Capacity and Energy produced by the QF.

TERMS OF SERVICE:

1. It shall be the QF's responsibility to inform KUA of any change in its electric generation capability.

2. Any electric service delivered by KUA to the QF shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall prevail.

3. A security deposit by the QF shall be required in accordance with KUA's rules and regulations and the following:

   A. In the first year of operation, the security deposit shall be based upon the singular month in which the QF's projected purchases from KUA exceed, by the greatest amount, KUA's estimated purchases from the QF. 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 QF and KUA 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 QF exceed the actual sales to KUA in that month.

4. KUA shall specify the point of interconnection and the voltage level.

5. KUA will, under the provisions of this Rate Schedule, require a Parallel Operation Agreement between the QF and the electric utility in whose service territory the QF's generating facility is located. The QF shall

recognize that its generation facility located in KUA's service territory may exhibit unique interconnection requirements which will be separately evaluated by KUA, modifying KUA's safety and technical standards where applicable.

6. Service under this Rate Schedule is subject to the rules and regulations of KUA.

SPECIAL PROVISIONS:

1. Special contracts deviating from this Rate Schedule are allowable provided they are agreed to by KUA.

2. A QF located within KUA's service territory may sell Firm Capacity and Energy to a utility other than KUA when adequate transmission capacity is available on KUA's system. In addition, KUA will provide transmission wheeling service through its service territory, when adequate transmission capacity exists, for a QF located outside KUA's service territory applicable to the delivery of the QF's power to the purchasing utility or to an intermediate utility. When such conditions exist, KUA will provide transmission wheeling service to deliver the QF's power to the purchasing utility or to an intermediate utility. In either case, KUA will charge for wheeling QF Firm Capacity and Energy pursuant to the provisions of KUA's Rate Schedule CG-3 for Transmission Service for a QF.

3. KUA shall be relieved of its obligation to purchase and pay for electric capacity and energy from a QF when purchases result in higher costs to KUA than without such purchases, and where service to KUA's other customers may be impaired by such purchases. On such occasions, KUA shall notify the QF as soon as possible or practical.

Appendix A

KUA's Agreement for Supplemental Resale Service with Florida Power Corporation in its entirety is incorporated herein by reference.

<u>AGREEMENT</u>
<u>FOR</u>
<u>SUPPLEMENTAL RESALE SERVICE</u>

Dated:

Parties: Florida Power Corporation
3201 - 34th Street South
P. O. Box 14042
St. Petersburg, Florida 33733
(The Company)

and

Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, Florida 34742-3219
(The Customer)

1. <u>SCOPE OF AGREEMENT.</u> The Company agrees to sell and deliver to the Customer, and the Customer agrees to purchase from the Company, and to pay for, Supplemental Resale Service under the terms set forth in the following exhibits, which are incorporated herein and made a part hereof:

   a. The applicable rate provisions and terms and conditions specific to each type of service provided under this Agreement are contained in Exhibit A, consisting of Schedule 1 for Supplemental Resale Service.

   b. The terms and conditions general to all types of service provided under this Agreement are contained in Exhibit B.

c. The delivery points served under this Agreement are listed in Exhibit C.

d. The Company's Resources & Customer's % KW allocation are listed in Exhibit D.

2. __AMENDMENT OF AGREEMENT.__ Exhibit A (consisting of Schedule 1), Exhibit B and Exhibit D of this Agreement may be amended or superseded from time to time by the Company by notifying the Customer in writing of such change and making the appropriate filing with the Federal Energy Regulatory Commission or such other agency as may have jurisdiction; provided, however, no such filing (unless agreed to by the Customer in writing) shall be made without giving the Customer at least sixty (60) days prior written notice of the filing. Any change shall become effective as permitted under Section 205 of the Federal Power Act or other applicable statute. Exhibit C may be amended when a new delivery point is added or an existing delivery point is abandoned.

3. __TERM OF AGREEMENT.__ This Agreement shall become effective on the date that the Agreement is permitted to become effective by the Federal Energy Regulatory Commission as a rate schedule under the Federal Power Act and shall remain in effect thereafter until and unless terminated by either party in accordance with Article 1 of the General Terms and Conditions of Service in Exhibit B hereof.

IN WITNESS WHEREOF, the parties hereto have caused this instrument to be executed by their respective authorized officials.

KISSIMMEE UTILITY AUTHORITY
(Customer)

By: Richard F. Hord
Chairman, Board of Directors

Attest: B.J. Bobrotti
Secretary
Dated: Nov. 2, 1989

APPROVED AS TO FORM
By: Edward P. Branan
KUA Attorney
Dated: 11-2-89

FLORIDA POWER CORPORATION
(Company)

By: Maurice H. Phillips
Maurice H. Phillips
Executive Vice President

Attest: Diane Huozai
Dated: 10/27/89

FLORIDA POWER CORP.
LEGAL DEPT.
APPROVED
Date 10-26-89
By [illegible]

AGREEMENT

FOR

SUPPLEMENTAL RESALE SERVICE

RATE SCHEDULE

Schedule 1: Supplemental Resale Service

SUPPLEMENTAL RESALE SERVICE
TO
KISSIMMEE UTILITY AUTHORITY

RATE SCHEDULE

Section I. Availability

Supplemental Resale Service is available from the Company to the Customer at existing delivery points on the Company's interconnected system and at such other delivery points on the system as may be agreed upon by the Company and the Customer. The service under this rate schedule is 60 cycle alternating current of the phase and Company's standard nominal voltage desired by the Customer at the delivery points, provided electric service of the voltage desired by the Customer is available generally in the area in which such service is desired.

Section II. Applicability

This rate schedule is applicable to firm capacity and associated energy purchased from the Company by the Customer for its own use, to supplement other capacity and energy resources supplied by the Customer, for resale to its retail customers at delivery points covered by the Agreement, or for resale to parties other than the Customer's retail customers. Such capacity and associated energy shall be purchased by the Customer as Base Demand and, in certain circumstances, Excess Demand. The Customer's Base Demand shall be established as provided in Section IV (A) of this Exhibit A, Schedule 1, of the Agreement. The Customer's Excess Demand shall be established as provided in Section IV (B) of this Exhibit A, Schedule 1, of the Agreement. This rate schedule is not applicable to capacity or energy purchased under any contract for interchange service between Florida Power Corporation and Kissimmee Utilities Authority.

The Customer may make purchases of Base Demand and Excess Demand and associated energy under this rate schedule for three categories of resale:

Category #1: Resales of Base Demand, Excess Demand and associated energy to the Customer's retail customers.

Category #2: Resales of firm capacity and associated energy to parties other than the Customer's retail customers and other full requirements customers.

Category #3: Resales of energy to parties other than the Customer's retail customers and other full requirement customers (transactions on the Broker System).

Purchases for resale of Basic Demand, Excess Demand and associated energy for Category #1 resales, firm capacity and associated energy for Category #2 resales, energy for Category #3 resales shall all contribute to the "Peak Scheduled KW," if such resales occur at the hour of the Company's system peak demand for the billing month, and "Maximum Scheduled KW" for purposes of computing the Base Demand and Excess Demand under Sections IV (A) and IV (B) of this Exhibit A, Schedule 1, of the Agreement.

This rate schedule is not applicable to sales of energy for Category #3 resales in any hour in which the total charge imposed hereunder for such energy (the charge not to include any charge for demand) is estimated to be less than the Company's incremental cost (to be supplied by the Company to the Customer before each hour, if requested) in that hour of producing and delivering such energy, and the Company may decline to provide energy for Category #3 resales in such hours under this rate schedule.

Section III. Monthly Rates and Charges

Supplemental Resale Service is stratified into Base Supplemental Resale Service, Intermediate Supplemental Resale Service, and Peaking Supplemental Resale Service. Supplemental Resale Service shall be billed on a calendar month basis at the sum of the amounts determined by applying the following rates and charges to the billing determinants found as described hereafter for the billing month:

A. <u>Monthly Basic Generating Demand Rates</u> - Applicable to Sales for Categories #1, #2, and #3 resales.

Base Supplemental Resale Service Demand Rate Per KW Per Month	$10.066
Intermediate Supplemental Resale Service Demand Rate Per KW Per Month	$ 4.628
Peaking Supplemental Resale Service Demand Rate Per KW Per Month	$ 3.479

B. <u>Monthly Excess Demand Rates</u> - Applicable to Sales for Categories #1, #2, and #3 resales.

Excess Base Supplemental Resale Service Demand Rate Per KW Per Month	$12.583
Excess Intermediate Supplemental Resale Service Demand Rate Per KW Per Month	$ 5.785
Excess Peaking Supplemental Resale Service Demand Rate Per KW Per Month	$ 4.349

C. <u>Monthly Non-Fuel Energy Rates</u> (to apply to energy associated with Base Demand and Excess Demand) - Applicable to Sales for Categories #1, #2, and #3 resales.

Base Supplemental Resale Service Non-Fuel Energy Rate Per KWH Per Month	$.00379
Intermediate Supplemental Resale Service Non-Fuel Energy Rate Per KWH Per Month	$.00711
Peaking Supplemental Resale Service Non-Fuel Energy Rate Per KWH Per Month	$.00711

D. **Monthly Fuel Charge** (to apply to energy associated with Base Demand and Excess Demand)

1. **For Sales for Categories #1 and #3 Resales**

The Fuel Charge for sales of energy for Category #1 and #3 resales shall be stratified into a Base Fuel Charge per KWH, an Intermediate Fuel Charge per KWH, and a Peaking Fuel Charge per KWH at the transmission delivery voltage level using actual system fuel costs for the billing month.

For purposes of such stratification, the following definitions shall apply: (1) The Base Resources are the Company's nuclear unit, coal units, oil units which are considered to be base resource reserves (all as listed in Exhibit D of this Agreement), and all purchases which have an if-generated per unit fuel cost below 110% of the per unit fuel cost of the highest cost Company-owned unit in the Base Resources. (2) The Intermediate Resources are all the Company's remaining steam oil units (as listed in Exhibit D of this Agreement), and all purchases which have an if-generated per unit fuel cost below 110% of the per unit fuel cost of the highest cost Company-owned unit in the Intermediate Resources. (3) The Peaking Resources are all remaining resources, both units and purchases. (4) The Base System Sales are all interchange sales by the Company, to all purchasers, which have a per unit fuel cost below the per unit fuel cost of the highest cost Company-owned unit in the Base Resources. (5) The Intermediate System Sales are all interchange sales by the Company to all purchasers, which have a per unit fuel cost below the per unit fuel cost of the highest cost Company-owned unit in the Intermediate Resources. (6) The Peaking System Sales are all remaining interchange sales by the Company. (7) The Base Energy is the billable amount of KWH of the Base Supplemental Resale Service sold to the Customer in the billing month. (8) The Intermediate Energy is the billable amount of KWH of the Intermediate Supplemental Resale Service sold to the Customer in the billing month. (9) The Peaking Energy is the billable amount of KWH of the Peaking Supplemental Resale Service sold to the Customer in the billing month. (10) The System Base Energy is the total amount of KWH generated by the Base Resources less Base System Sales less transmission losses. (11) The System Intermediate Energy is the total amount of KWH generated by the Intermediate Resources less Intermediate System Sales less transmission losses. (12) The System Peaking Energy is the total amount of KWH generated by the Peaking Resources less Peaking System Sales less transmission losses. (13) The Fuel Costs are costs as defined in Section 35.14, as amended, effective February 13, 1984, of the Regulations under the Federal Power Act, Title 18, Part One, Subchapter B of the Code of Federal Regulations or as otherwise ordered by the Federal Energy Regulatory Commission.

Purchase charges, other than those for fuel and energy, as permitted under Section 35.14 (as amended effective 2/13/84) will be included in fuel cost calculations under this clause to the extent such purchases are not required to meet system reserve capacity criteria. System reserve capacity criteria will be deemed to be satisfied when available power resources (exclusive of purchases for which recovery is sought) are equal to, or greater than, anticipated firm customer peak load plus the Company's share of State Operating Reserves, as established by the Florida Coordinating Group from time to time.

Non-fuel purchased economic power cost included in fuel cost calculations shall not include any such charges reflected in base rates for service.

The Base Fuel Charge shall be found by (1) determining the total fuel costs of the Base Resources for the billing month, (2) subtracting from that amount the total fuel costs of Base System Sales for the billing month and (3) dividing the remainder by the System Base Energy for the billing month. The Intermediate Fuel Charge shall be found by (1) determining the total fuel costs of the Intermediate Resources for the billing month, (2) subtracting from that amount the total fuel costs of the Intermediate System Sales for the billing month and (3) dividing the remainder by the System Intermediate Energy for the billing month. The Peaking Fuel Charge shall be found by (1) determining the total fuel costs of the Peaking Resources for the billing month, (2) subtracting from that amount the total fuel costs of the Peaking System Sales for the billing month and (3) dividing the remainder by the System Peaking Energy for the billing month.

2. <u>For Sales for Category #2 Resales</u>

The Fuel Charge for sales of energy for Category #2 resales shall employ the Fuel Charge specified above for sales for Categories #1 and #3 resales if such Category #2 resales maintain a billing month load factor equal to or greater than the Supplemental Resale Service billing month load factor calculated absent the sales for Category #2 resales. If the billing month load factor for sales for Category #2 resales is less than the Supplemental Resale Service billing month load factor calculated absent the sales for Category #2 resales, the Fuel Charge shall be the greater of:

a. The Company's incremental cost of fuel for sales for Category #2 resales determined on an hour-by-hour basis divided by such sales for the billing month; or

b. The Fuel Charge as set out above for sales for Categories #1 and #3 resales.

The determination of the greater of the two above amounts is to be made on a hour-to-hour basis for the billing month.

Within 10 days after the end of each billing month, the Customer shall supply the Company with the amounts and times of any resold energy purchased by the Customer for Categories #2, and #3 resales in order that the fuel charge for that energy can be determined in accordance with Section III (D) of this Exhibit A, Schedule 1, of the Agreement.

The Company shall furnish to the Customer a report showing the calculation of the Base Fuel Charge, Intermediate Fuel Charge, and the Peaking Fuel Charge for each billing month.

E. Monthly Rate for Transmission of Supplemental Resale Service

Transmission Service Rate (to all delivery points)

Demand Rate Per KW Per Month

$1.445

F. Monthly Customer Service Charge

The Customer shall pay a customer service charge of $191 per delivery point per month for Partial Requirements Resale Service. This charge shall be payable whether or not the Customer takes delivery of any capacity or energy of Partial Requirements Resale Service in the particular billing month.

Section IV. Monthly Billing Determinants

The billing determinants for the various components of the above rates and charges are defined below. Terms used in defining the billing determinants are Base Peak Scheduled KW, Intermediate Peak Scheduled KW, Peaking Peak Scheduled KW, Base Maximum Scheduled KW, Intermediate Maximum Scheduled KW, Peaking Maximum Scheduled KW, Base Scheduled KWH, Intermediate Scheduled KWH, Peaking Scheduled KWH, Base Contract Demand, Intermediate Contract Demand, and Peaking Contract Demand.

The Base Peak Scheduled KW, Intermediate Peak Scheduled KW and **Peaking Peak Scheduled KW** shall be the KW of capacity purchased under this Exhibit A, Schedule 1, of the Agreement and scheduled at the transmission delivery voltage level for delivery of such respective amount of **Base Peak Scheduled KW, Intermediate Peak Scheduled KW and Peaking Peak Scheduled KW** to the delivery points at the hour of the Company's system peak demand for the billing month.

The Base Maximum Scheduled KW, Intermediate Maximum Scheduled KW and Peaking Maximum Scheduled KW shall be the maximum KW of capacity purchased under this Exhibit A, Schedule 1, of the Agreement and scheduled at the transmission delivery voltage level for delivery to the delivery points during any hour for the billing month.

The Base Scheduled KWH, Intermediate Scheduled KWH and Peaking Scheduled KWH shall be the sum of the hourly scheduled KWH of energy at the transmission voltage level scheduled for delivery of such respective amount of **Base Scheduled KWH, Intermediate Scheduled KWH and Peaking Scheduled KWH** to the delivery points during each hour of the billing month.

The Base Contract Demand, Intermediate Contract Demand and Peaking Contract Demand in KW for each calendar year shall be the KW specified as Base Contract Demand, Intermediate Contract Demand and Peaking Contract Demand for that month according to Article 2 of this Exhibit A, Schedule 1, of the Agreement, except that in the event that an Excess Demand is established in any of the three stratified service areas in a given billing month, the previously established Contract Demand amounts in the respective stratified service area in each of the succeeding 11 months shall be increased by the amount of that Excess Demand. In the event of successive Incidents of Excess Demand, the addition of the Excess Demand to the Contract Demand shall be cumulative.

(For example, the 1992 Base Contract Demand is 40 MW and the 1993 Base Contract Demand is 50 MW. In June 1992, the Base Maximum Scheduled KW was 45 MW; therefore, the Base Excess Demand is established to be 5 MW. The Base Contract Demand for the succeeding eleven (11) billing months will be increased by 5 MW. Therefore, the Base Contract Demand is 45 MW for July 1992 through December 1992 and 55 MW for January 1993 through May 1993, and 50 MW for June 1993 through December 1993. In August of 1992, the Base Maximum Scheduled KW was 55 MW; therefore, the Base Excess Demand is established to be 10 MW. The Base Contract Demand is 55 MW for September 1992, through December 1992 and 65 MW for January 1993 through May 1993 and 60 MW for June 1993 through July 1993 and 50 MW for August 1993 through December 1993).

Monthly Billing Determinants:

A. For the Basic Generating Demand Rates for Supplemental Resale Service:

The demand in KW for the Base Supplemental Resale Service Demand Rate for each billing month shall be the higher of the Base Peak Scheduled KW or the Base Contract Demand for the subject billing month.

The demand in KW for the Intermediate Supplemental Resale Service Demand Rate for each billing month shall be the higher of the Intermediate Peak Scheduled KW or the Intermediate Contract Demand for the subject billing month.

The demand in KW for the Peaking Supplemental Resale Service Demand Rate for each billing month shall be the higher of the Peaking Peak Scheduled KW or the Peaking Contract Demand for the subject billing month.

B. For the Excess Demand Rate for Supplemental Resale Service:

The demand in KW for the Base Excess Demand Rate, Intermediate Excess Demand Rate and Peaking Excess Demand Rate for each billing month shall be the Base Maximum Scheduled KW less the Base Contract Demand, the Intermediate Maximum Scheduled KW less the Intermediate Contract Demand, the Peaking Maximum

Scheduled KW less the Peaking Contract Demand for that month. In no event shall the excess demands be a negative value.

C. <u>For the Non-Fuel Energy Rate for Supplemental Resale Service:</u> The energy in KWH for the Non-Fuel Energy Rate for each billing month shall be the Base Scheduled KWH, Intermediate Scheduled KWH and Peaking Scheduled KWH for that month.

D. <u>For the Fuel Charge for Supplemental Resale Service:</u> The energy in KWH for the Fuel Charge for each billing month shall be the same as specified in paragraph C above.

E. <u>For the Rate for Transmission of Supplemental Resale Service:</u> The demand in KW for the Rate for Transmission of Supplemental Resale Service for each billing month shall be the sum of Base Peak Scheduled KW, Intermediate Peak Scheduled KW and Peaking Peak Scheduled KW.

TERMS AND CONDITIONS OF SERVICE SPECIFIC TO SUPPLEMENTAL RESALE SERVICE

ARTICLE 1. RECIPROCAL COMMITMENTS TO PURCHASE AND SELL ALL SUPPLEMENTAL RESALE SERVICE

The Company commits that it will supply as Supplemental Resale Service under this Agreement all of the Base Demands and the Excess Demands and energy associated therewith as determined under the provisions of this Agreement. The Customer commits that it will pay the charges specified for such service in this Agreement.

ARTICLE 2. THE CUSTOMER'S CONTRACT DEMAND

Upon the execution of this Agreement, the Customer shall provide the Company an initial written specification of annual Contract Demand levels for Base, Intermediate and Peaking Supplemental Service for the five calendar years 1990 through 1994. These Base, Intermediate and Peaking Contract Demand levels in any year shall not exceed their respective % KW allocation contained in Exhibit D times the Customer's most recent historical system peak demand KW adjusted for the most recent 5 year average growth rate. These Contract Demand levels shall be designated as:

Initial Specified 1990 Base, Intermediate & Peaking Contract Demands

Initial Specified 1991 Base, Intermediate & Peaking Contract Demands

Initial Specified 1992 Base, Intermediate & Peaking Contract Demands

Initial Specified 1993 Base, Intermediate & Peaking Contract Demands

Initial Specified 1994 Base, Intermediate & Peaking Contract Demands

Starting in 1990, the annual Contract Demand specifications for Base, Intermediate & Peaking Supplemental Service made the previous year shall be updated by May 31 of the current year, and an initial specification shall be made for the Contract Demands for the fifth future year. The updated Contract Demand amounts shall be within certain ranges of the previously-specified amounts as set out below:

By May 31 of current Year, Provide Updated Contract Demand Values:	Range
Update of First Future Year Base, Intermediate & Peaking Contract Demands	Must Equal Previously-Specified Annual Contract Demands
Update of Second Future Year Base, Intermediate & Peaking Contract Demands	Previously-Specified Demand For That Year ± the greater of 10% or 10MW
Update of Third Future Year Base, Intermediate & Peaking Contract Demands	Previously-Specified Demand For That Year ± the greater of 15% or 15MW
Update of Fourth Future Year Base, Intermediate & Peaking Contract Demands	Previously-Specified Demand For That Year ± the greater of 20% or 20MW

Rate Schedule ______
EXHIBIT A, Schedule 1
Original Sheet No. 18

Initial Specification for Fifth Future Base, Intermediate & Peaking Contract Demands	Previously-Specified Demand For Fourth Future Year ± the greater of 20% or 20MW

For example, on or before May 31, 1990, the Customer shall provide an initial specification of the Customer's Base, Intermediate & Peaking Contract Demands for each month for calendar year 1995 and may adjust the initial specifications of the Customer's Base, Intermediate & Peaking Contract Demands for years 1992, 1993 and 1994 in accordance with the above limitations.

In addition to the above limitations, in no event shall the sum of the ~~the~~ updated Contract Demands for any year be more than the greater of 20% or 20MW above or below the initial specified Contract Demands for that year. In addition, the Base, Intermediate and Peaking Contract Demands shall not exceed the respective % KW contained in Exhibit D times the Customer's most recent historical system peak demand KW adjusted for the most recent 5 year average system growth rate.

In addition to the annual specification for the fifth future year provided for above, the Customer, at its option, may make a further specification for Contract Demands for the seventh future calendar year. Such specifications for the seventh future calendar year shall not be higher (unless the Company agrees in writing that it may be higher) than the specifications for the fifth calendar year, but may, without limitation, be lower than the specifications for the fifth future calendar year. Such specifications for the seventh future calendar year shall not be subject to change until the specifications become the fourth future year specifications as defined in the required rolling five-year specifications. Once such specifications for the seventh future calendar year become the fourth future year specifications or the specifications for any lesser future year, it may be updated but is subject to all limitations set out above.

If the Customer does not provide annual written Base, Intermediate & Peaking Contract Demand Specifications in accordance with this Article II, the Company shall have the option of specifying the Base, Intermediate & Peaking Contract Demands for the Customer. Any such written specifications by the Company shall have the same effect as written specifications by the Customer.

Any adjustment or revision to specified Base, Intermediate & Peaking Contract Demands that does not conform to the above restrictions and limitations may be made only by mutual consent of the Company and the Customer expressed in writing.

ARTICLE 3. HOURLY SCHEDULING OF CAPACITY AND ENERGY

The amount of Base, Intermediate & Peaking capacity and associated energy supplied under this Agreement shall initially be requested and delivered on an hourly basis according to the then effective interchange agreement between the Company and Kissimmee Utilities Authority, or any successors thereto.

ARTICLE 4. GENERAL TERMS AND CONDITIONS

Service under this Exhibit A, Schedule 1, of the Agreement is subject to the General Terms and Conditions of Service in Exhibit B of the Agreement as that Exhibit may be in effect from time to time pursuant to the Federal Power Act.

ARTICLE 5. AMENDMENT OF THIS EXHIBIT A, SCHEDULE 1

This Exhibit A, Schedule 1, of the Agreement may be amended or superseded from time to time by the Company by notifying the Customer in writing of the change and making the appropriate filing with the Federal Energy Regulatory Commission or such other agency as may have jurisdiction; provided, however, no such filing (unless agreed to by the Customer in writing) shall be made without giving the Customer at least sixty (60) days prior written notice of the filing. Any change shall become effective as permitted under Section 205 of the Federal Power Act or other applicable statute.

AGREEMENT

FOR

SUPPLEMENTAL RESALE SERVICE

GENERAL TERMS AND CONDITIONS OF SERVICE

TO

KISSIMMEE UTILITY AUTHORITY

GENERAL TERMS AND CONDITIONS OF SERVICE
TO
KISSIMMEE UTILITY AUTHORITY

ARTICLE 1. TERMINATION OF AGREEMENT

Either party may terminate this Agreement by giving notice in any calendar year after the calendar year 1999 that the Agreement shall terminate at the end of the fifth future calendar year (that is, for example, either party may give notice in calendar year 2000 that the Agreement will terminate at the end of the calendar year 2005). The applicable provisions of this Agreement shall continue in effect after the term of the Agreement to the extent necessary to provide for final billings and adjustments and to preserve, enforce or bring action upon any rights or obligations under the Agreement not exercised or fulfilled upon termination.

ARTICLE 2. DELIVERY POINTS

The Company shall deliver capacity and energy hereunder to the Customer at the points at which the facilities of the Customer are directly connected to the Company's interconnected electric system. New or different delivery points may be established by written agreement of the Company and the Customer. All capacity and energy delivered at any time under any of the rate schedules in Exhibit A of the Agreement shall be deemed to have been supplied to the aggregate of all delivery points served under this Agreement.

ARTICLE 3. PERMITS AND EASEMENTS

Each party shall furnish or arrange to have furnished all permits and easements which are necessary for the construction and maintenance of the facilities required for delivery of capacity or energy hereunder on its respective side of the delivery point. The obligation of the Company and the Customer are subject to and conditioned upon their securing and retaining all permits and easements and other rights and approvals necessary for service to be rendered.

ARTICLE 4. SERVICE FACILITIES AND METERING

The Company and the Customer each shall furnish, install, maintain, own and operate, at its sole cost and expense, all lands and equipment located on its side of the delivery point unless otherwise specified in writing.

ARTICLE 5. ACCESS FOR COMPANY EMPLOYEES

The Company shall have the right, authority and privilege to enter upon the premises of the Customer at all reasonable times for the purpose of reading meters, inspecting or repairing apparatus used in connection with the service, removing its property or any other purpose to carry on the work of the Company in connection with rendering the service hereunder, and to do all things necessary and expedient in the proper operation of its business, but in exercising such right, authority and privilege, the Company shall assume all liability for damage or personal injury caused by the negligence of the Company.

ARTICLE 6. USE OF SERVICE

The Customer and the Company shall cooperate in obtaining the most efficient use of their facilities and shall avoid insofar as practicable the imposition of low power factor or widely fluctuating loads or unbalanced loads.

ARTICLE 7. PAYMENT OF BILLS

Bills for service shall be rendered monthly by Company and shall be due when rendered and payable within twenty (20) days from date of bill. Bills not paid within twenty (20) days from the date of the bill shall be deemed delinquent and shall accrue interest at the current annual rate provided for refunds made under the Federal Power Act by the Federal Energy Regulatory Commission or any successor agency. In the absence of such an interest rate, interest shall accrue at the rate of one percent (1%) per month. In the case of a disputed bill, payment of the disputed portion may be (1) made by the Customer to the Company during the twenty (20) day payment period, in which case any portion finally determined not to be owing shall be refunded by the Company with interest computed as set out above for the period after the twenty (20) day payment period, or (2) withheld by the Customer until the dispute is finally resolved, in which case the Customer shall pay the amount finally determined to be owing with interest computed as set out above for the period after the twenty (20) day payment period.

In the event of non-payment of a bill by the Customer except under the disputed bill provision immediately above, the Company shall have the right to terminate service at least sixty (60) days subsequent to the date of the bill. The Company shall be required to notify the Customer in writing of its intent to terminate service for non-payment of a bill at least thirty (30) days prior to the actual date of termination of service.

ARTICLE 8. CONTINUITY OF SERVICE

The Company shall exercise due care and diligence to supply electric service hereunder free from interruption; provided, however, the Company shall not be responsible for any failure to supply electric service, nor for interruption, reversal or abnormal voltage of the supply, if such failure, interruption, reversal or abnormal voltage is without negligence on its part. Whenever the integrity of the Company's system or the supply of electricity is threatened by conditions on its system or on the systems with which it is directly or indirectly interconnected, or whenever it is necessary or desirable to aid in the restoration of service, the Company may, in conformance with sound operating and engineering practices and with the application of standards no more interruptive than applied in service to its retail customers in like circumstances, curtail or interrupt electric service or reduce voltage to some or all of the delivery points of the Customer, and such curtailment, interruption or reduction shall not constitute negligence by the Company.

ARTICLE 9. LIABILITY

Each party expressly agrees to indemnify and save harmless and defend the other against all claims, demands, costs or expense for loss, damage or injury to persons or property in any manner directly or indirectly connected with, or growing out of, the generation, transmission or distribution of electric energy on its own side of the delivery point hereunder, unless such claim or demand shall arise out of or result from the negligence or willful misconduct of the other party, its agents servant or employees.

ARTICLE 10. DELIVERY VOLTAGE

The Company and the Customer shall maintain close coordination with respect to future delivery points in the interests of system reliability and overall economics. Each party will endeavor, to the extent practicable, to keep the other party advised of significant developments related to their respective power supply facilities.

The Company shall not be required to establish a new delivery point or change the voltage of an existing delivery point until written agreement is reached between the Company and the Customer as to which one shall bear the cost or as to the ratio in which each shall bear the cost of the new facilities.

ARTICLE 11. INTERPRETATION

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of Florida.

ARTICLE 12. NOTICES

Notices and written communications under this Agreement shall be addressed to the President of the Company and to the General Manager of the Customer at their respective corporate headquarters or to such other persons as the parties may designate in writing from time to time.

ARTICLE 13. PRIOR AGREEMENTS

This Agreement represents the complete understanding of the Company and the Customer and any prior agreement or understanding between the Company and the Customer regarding the subject of this Agreement is merged herein and superseded hereby.

ARTICLE 14. GOVERNMENTAL AUTHORITY

All obligations of the Company and the Customer are subject to action of such federal or state regulatory agencies or other governmental authority as may have jurisdiction.

ARTICLE 15. SUCCESSORS

This Agreement shall inure to the benefit of, and shall bind the successors of the parties hereto but shall not be assignable by either party without the written consent of the other.

ARTICLE 16. FURTHER COMMITMENTS

At the request of the Company, the Customer shall provide a twenty (20) year forecast of its monthly total loads and energy within the Company's system for planning purposes on or before May 31 of each year. However, it is understood that these estimates are subject to change as required.

ARTICLE 17. AMENDMENT OF THIS EXHIBIT B

This Exhibit B of the Agreement may be amended or superseded from time to time by the Company by notifying the Customer in writing of such change and making the appropriate filing with the Federal Energy Regulatory Commission or such other agency as may have jurisdiction; provided, however, no such filing (unless agreed to by the Customer in writing) shall be made without giving the Customer at least sixty (60) days prior written notice of the filing. Any change shall become effective as permitted under Section 205 of the Federal Power Act or other applicable statute.

AGREEMENT
FOR
SUPPLEMENTAL RESALE SERVICE

LIST OF DELIVERY POINTS

Designation	Volts
Lake Bryan Sub	69 KV

AMENDMENT OF THIS EXHIBIT C

This Exhibit C may be amended when a new delivery point is added or an existing delivery point is abandoned.

AGREEMENT
FOR
SUPPLEMENTAL RESALE SERVICE

Company Resources

BASE

Anclote Units #1-2
Crystal River Units #1-5

Intermediate

Bartow #1-3
Higgins #1-3
Suwannee #1-3
Turner #2-4

Peaking

All Peaking Units

Customer's % KW Allocation

Base:	~~35%~~ 36%
Intermediate:	40%
Peaking:	24%

Amendment of this Exhibit D

This Exhibit D of the Agreement may be amended or superseded from time to time by the Company by notifying the Customer in writing of such change and making the appropriate filing with the Federal Energy Regulatory Commission or such other agency as may have jurisdiction. Any change shall become effective as permitted under Section 205 of the Federal Power Act or other applicable statute.

STANDARD RATE FOR TRANSMISSION SERVICE FOR QUALIFYING FACILITIES RATE SCHEDULE CG-3

AVAILABILITY:

Transmission service hereunder is available over KUA facilities to or from existing points of delivery and such other points as may be established on KUAs system. Firm and nonfirm transmission service is available where and so long as KUAs facilities have adequate capacity to permit the transmission requested by the Qualifying Facility (QF) on a technically feasible basis without adversely affecting the adequacy, reliability, or cost of providing electric service to KUA's retail and other customers.

Firm Transmission Service

Firm transmission service for Firm Capacity and Energy shall be provided on a continuous basis for a specified quantity of power to be transmitted for the duration of an agreed upon commitment period so long as there is sufficient unused capacity in KUAs transmission facilities to provide such service.

A Letter of Commitment shall be required between the QF and KUA specifying the quantity of power to be transmitted (the "Contract Demand") and the period of time for which such deliveries are requested. Prior to entering into such Letter of Commitment, KUA may perform or may have performed, at the expense of the QF, load flow and stability studies of its system to determine whether or not the requested service will adversely affect the adequacy, reliability, or cost of providing electric service to KUA's retail and other customers. If the requested transmission service would require KUA to install new facilities, would cause it to install facilities significantly earlier than it would otherwise do, or otherwise cause it to incur exceptional expense, KUA reserves the right to decline to provide service under this tariff and, at its option, may offer transmission service under a compensatory contract. Such compensatory contract would, to the extent appropriate in the circumstances, follow the provisions of this transmission service tariff and its associated terms and conditions.

Non-Firm Transmission Service

Non-firm transmission service for As-Available Energy shall be provided on a when-, as-, and if-available basis and such service is interruptible at the sole option of KUA. KUA will provide notification of interruptions of non-firm transmission service at least one hour prior to such interruption, to the extent possible. Such service shall be provided only if there is sufficient unused capacity in KUAs transmission facilities.

In the event the QF fails to interrupt or curtail its use of Non-firm transmission service within on hour upon notification to so do by KUA, then such service shall, for billing purposes only, be considered as Firm transmission service and billed as such by KUA for the current and succeeding eleven billing months, but shall in all other respects still be considered as Non-firm transmission service. Non-firm transmission service is not available for transmission of Firm Capacity and Energy.

APPLICATION:

This Rate Schedule shall apply to transmission service for any QF to which KUA is directly or indirectly interconnected for delivery of power generated by the QF to another electric utility. For purposes of this Rate Schedule, QF means a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Federal Energy Regulatory Commission's regulations under the Public Utilities Regulatory Policies Act of 1978, S201, with regard to cogeneration and small power production.

CHARACTER OF SERVICE:

The service under this Rate Schedule is 60 hertz, alternating current three phase at 69 kv or 230 kv transmission wheeling service.

LIMITATION OF SERVICE:

For both Firm and Nonfirm transmission service provided hereunder, KUA maintains the right at any time to deny, curtail, or discontinue transmission service (1) for interruptions or reductions due to force majeure; (2) for interruptions or reductions due to action instituted by automatic or manual control resulting in disconnection for the purpose of maintaining overall reliability and continuity of KUA's electric system or for the purpose of protecting KUA's generation or transmission or distribution facilities; (3) for temporary interruptions or reductions which, in the opinion of KUA, are necessary or desirable for the purpose of maintenance, repairs, replacements, or installation of equipment, or investigation and inspection; or (4) if KUA determines that the provision of such service would adversely affect the adequacy, reliability, or cost of providing electric service to KUA's retail or other customers.

Prior to initiating transmission service under this Rate Schedule, should the QF be located within KUA's electric system, KUA and the QF shall have executed a Parallel Operation Agreement covering the interconnected operations of KUA's and the QF's resources. Such agreement shall include, but not be limited to, the following topics:

A. Costs of interconnecting with the QF including specifically assigned costs to be paid by the QF, and any additional administrative and general expenses incurred by KUA to be paid by the QF;

B. safety and technical standards for parallel operation;

C. automatic and manual disconnection requirements;

D. output compatibility;

E. inadvertent energy flows;

F. protective equipment requirements;

G. metering provisions, including type, ownership, location, access, and testing;

H. indemnification, force majeure, insurance, and term; and

I. reactive power penalty clause.

Prior to initiating transmission service under this Rate Schedule, if the QF is not located within KUA's electric system and requires transmission service over KUA's electric system, the QF shall provide KUA a copy of all executed agreements required to transmit capacity and energy from the QF's generating facilities to and from KUA's electric system and execute an agreement with KUA addressing the above listed items as appropriate.

TRANSMISSION RATES:

Firm and Nonfirm transmission rates shall be based on KUA's projected revenue requirements associated with providing transmission service.

LOSSES:

KUA shall receive capacity and energy from the QF for delivery and shall deliver at KUA's interconnection points with other utilities such amount received less an amount attributable to losses. These losses will be based on KUA's most recent annual data for the applicable loss percentage factor. If, in KUA's judgment, the use of average losses would not result in equitable compensation for losses incurred, incremental losses attributed to the transaction may be used. When incremental losses are to be used, the QF shall be so advised at least 30 days prior to the transaction.

VOLTAGE LEVEL ADJUSTMENTS:

Transmission rates developed under this Rate Schedule shall be calculated to account for voltage level adjustments, if any.

DETERMINATION OF BILLING DEMAND:

Monthly charges for Firm transmission service shall be based on the monthly rate per kW multiplied by the Contract Demand in kW established in the Letter of Commitment. Monthly charges for Nonfirm transmission service shall be based on the rate per kWh multiplied by the energy scheduled to be received by KUA and to be transmitted over KUA's system for the month.

TERMS OF PAYMENT:

Bills for transmission service shall be rendered monthly by KUA to the QF. All such bills shall be due and payable within ten (10) days from the date of mailing. Any amount due and unpaid after the due date shall be termed delinquent and there shall be added interest of one percent (1%) per month and an additional one percent (1%) for each month thereafter.

POWER FACTOR:

It shall be the responsibility of the QF receiving transmission services to supply enough reactive power to maintain the power factor of transmitted power as near unity as practicable.

SCHEDULED DELIVERIES:

It shall be the responsibility of the QF to arrange a schedule satisfactory to KUA for transmitted power and energy, up to the level of the Contract Demand, and to notify KUA of such schedule prior to commencement of the transaction. The QF shall furnish KUA a 24-hour schedule by noon of the prior day. The amount scheduled to be delivered will be rounded to the nearest whole MW for dispatching purposes only.

CONTINUITY OF TRANSMISSION SERVICE:

KUA does not guarantee that the transmission service delivered hereunder will be free from interruption or impairment, and KUA shall not be liable for damages resulting therefrom.

NO DEDICATION OF FACILITIES:

Any undertaking by one party to the other party under any provision of this Rate Schedule shall not constitute the dedication of the system or any portion thereof, of any party to the public or to the other party, and it is understood and agreed that any such undertaking by any party shall cease upon termination of this Rate Schedule.

TRANSMISSION BY THIRD PARTIES AND BACKUP GENERATION SERVICES:

The QF is responsible for all necessary transmission arrangements with any third parties and for backup generation services and shall also be responsible for all costs associated with transmission by other parties and for backup generation services.

CHANGES IN RATE SCHEDULE:

KUA may change the provisions of this transmission Rate Schedule, including the rates and associated terms and conditions, by notifying the QF in writing of such changes at least sixty (60) days in advance.

NOTICE:

Any notice, demand, or request required or authorized by this Rate Schedule shall be deemed properly given if mailed, postage prepaid, to:

A. Notice to KUA from QF:

Kissimmee Utility Authority, Post Office Box 423219, Kissimmee, Florida 32742-3219; Attention: Director of Power Supply. Such notice, demand, or request must then be acknowledged and consented to by KUA in writing, or by telephone call by the Director or his designee.

B. Notice to QF by KUA:

____

____

Such notice, demand, or request must then be acknowledged and consented to by ______________ in writing, or by telephone call by ______________, or his designee.

The designation of the person to be notified or the address of such person may be changed at any time, or from time to time by similar notice.

TRANSMISSION SERVICE RATES:

Non-Firm Transmission Service

The rate for the transmission of as-available energy shall be $2.14 per MWh received by KUA for delivery on behalf of the QF.

Firm Transmission Service

The annual rate for transmission of firm capacity and energy on behalf of the QF shall be $18,781 per MW of contracted demand. Monthly billing shall be one-twelfth of the calculated annual charge.

STANDARD OFFER CONTRACT FOR THE PURCHASE OF AS-AVAILABLE ENERGY FROM A QUALIFYING FACILITY SOC-1

THIS AGREEMENT is made and entered into this __________ day of ____________, 19___, by and between the __________________________, (hereinafter referred to as the "QF") and Kissimmee Utility Authority, (hereinafter referred to as the "KUA"), a body politic, duly organized under the laws of the State of Florida. The QF and KUA shall collectively be referred hereinafter as the "Parties."

WITNESSETH:

WHEREAS, the QF, being certified as such, desires to sell, and KUA desires to purchase, nonfirm electricity to be generated by the QF consistent with the definitions and criteria contained in the Federal Energy Regulatory Commission Rules 292.101 and 292.301 through 292.308, effective March 20, 1980, and

WHEREAS, the QF has signed a Parallel Operation Agreement with the electric utility (including KUA) in whose service territory the QF's generating facility is located, which is attached hereto as Appendix __________; and

WHEREAS, for a QF not directly interconnected with KUA's electric system, the QF has entered into the necessary agreements required to have the capacity and energy delivered to KUA's electric system, which is attached hereto as Appendix _____;

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

Section 1. Facility

The QF has installed or operates or contemplates installing and operating a ____________________ kVA __________ generating facility located at ____________________. The generator is designed to produce a maximum of __________ megawatts (MW), or __________ kilowatts (kW) of electric power at an 85 percent lagging power factor (90 percent leading for induction generators), such equipment being hereinafter referred to as the "Facility."

Section 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___, or until terminated by written notice by either Party.

Section 3. Sale of Electricity by QF

KUA agrees to purchase electric power generated by the QF and transmitted to KUA by the QF as metered at the point of interconnection and, when applicable, adjusted for losses as appropriate.

KUA will make reasonable provisions to purchase As-Available Energy from the QF, but KUA will not make or accept such purchases of As-Available Energy from the QF to the extent such energy will jeopardize the integrity and/or reliability of KUA's system.

Section 4. Payment for Electricity Produced by QF

4.1 Energy. KUA agrees to pay for energy produced by the QF and delivered to KUA in accordance with the rates and provisions contained in Rate Schedule CG-1, and as may be amended from time to time.

Section 5. Electricity Production Schedule

During the term of the Agreement, the QF agrees, at its cost, to:

(A) Comply with reasonable requirements of KUA regarding day-to-day and hour-by-hour communications between the Parties relative to the performance of this Agreement;

(B) Provide all necessary information, including, but not limited to, data acquisition for real time telemetry and monitoring of actual generation output of the facility, requested by KUA to implement and administer this Agreement and applicable rate schedules;

(C) Adjust reactive power flow in the interconnection as may be reasonably required by KUA or the electric utility with which the QF has signed a Parallel Operation Agreement within the range of 90 percent leading to 85 percent lagging power factor unless otherwise provided in the Parallel Operation Agreement;

(D) Come off line quickly during emergencies where generation from the Facility would contribute to the overloading of the interconnected utility system; and

(E) Provide any additional criteria reasonably required by KUA related to the delivery of As-Available energy by the QF.

Section 6. General Provisions

6.1 Permits. The QF hereby agrees to obtain any and all governmental permits, certifications, or other authority that the QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. KUA hereby agrees, at the QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications, or other authority KUA is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

6.2 Indemnification. The QF agrees to indemnify and save harmless KUA and its respective employees, officers, directors, and agents against any and all liability, loss, damage, costs, or expense which KUA and its respective this Agreement, the Parties designate the following to be notified or to whom payment be sent until such time as either Party furnishes the other Party written instructions to contact another individual.

For the QF:

____

____

__________________________ Telephone ____________________

For KUA:

____

____

__________________________ Telephone ____________________

6.7 Tax Exemption. KUA shall not be required to take any action under this Agreement if such action, in the opinion of KUA, would have an adverse effect on the tax-exempt status of KUA's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

6.8 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida and any unresolved disputes, if litigated, shall be filed with the appropriate Florida courts.

6.9 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.

6.10 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.

6.11 Incorporation of Rate Schedule. The Parties agree that this Agreement shall be subject to all of the provisions contained in KUA's published Rate Schedule CG-1 as approved and amended from time to time. The Rate Schedule is incorporated herein by reference.

6.12 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 HEREOF, QF and KUA have executed this Agreement the day and year first above written.

Attested:

By:______________________________

Qualifying Facility

By:______________________________
Authorized Officer

Attested:

By:______________________________
Secretary

Kissimmee Utility Authority

By:______________________________
Chairman

Approved as to form and correctness:

____
Attorney

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A QUALIFYING FACILITY SOC-2

THIS AGREEMENT is made and entered into this ________ day of ____________, 19___, by and between the ______________________, the Qualifying Facility (hereinafter referred to as the "QF"), and Kissimmee Utility Authority, (hereinafter referred to as the "KUA"), a body politic, duly organized under the laws of the State of Florida. The QF and KUA shall collectively be referred hereinafter as the "Parties."

WITNESSETH:

WHEREAS, the QF, being certified as such, desires to sell, and KUA desires to purchase, electric power and energy generated by the QF consistent with the definitions and criteria contained in the Federal Energy Regulatory Commission Rules 292.101 and 292.301 through 292.301, effective March 20, 1980, and

WHEREAS, the QF has signed a Parallel Operation Agreement with the electric utility in whose service territory the QF's generating facility is located, which is attached hereto as Appendix ________; and

WHEREAS, for a the QF not directly interconnected with KUA's electric system, the QF has entered into the necessary agreements required to have the capacity and energy delivered to KUA's electric system, which agreements are attached hereto as Appendix ____;

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

Section 1. Facility

The QF has installed or operates or contemplates installing and operating a ________________ kVA ________ generating facility located at ________________. The generator is designed to produce a maximum of ________ megawatts (MW), or ________ kilowatts (kW) of electric power at an 85 percent lagging power factor (90 percent leading for induction generators), such equipment being hereinafter referred to as the "Facility."

Section 2. Term of the Agreement

This Agreement shall commence upon commercial operation of the Facility and shall end at 12:01 a.m., ________________, 19___.

If commercial operation of the Facility is not accomplished by the QF before a date agreed upon between the Parties, this Agreement shall be rendered of no force and effect and KUA shall be entitled to take any remedies available to it in accordance with Florida law.

KUA agrees to purchase electric power generated at the Facility and transmitted to KUA by the QF as metered at the point of interconnection and, when applicable, adjusted for losses as appropriate.

Section 4. Payment for Electricity Produced by QF

4.1 Energy. KUA agrees to pay the QF for energy produced by the Facility and delivered to KUA in accordance with the rates and provisions contained in Rate Schedule CG-2, as may be amended from time to time.

4.2 Capacity

4.2.1 Anticipated Committed Capacity. The QF expects to sell approximately __________ kW of capacity, beginning on or about ____________________, 19___.

The QF may finalize its Anticipated Committed Capacity after initial facility testing, and specify when capacity payments are to begin, by completing Section 4.2.2 at a later time. The QF must complete Paragraph 4.2.2 within 30 days after commercial operation of the Facility.

4.2.2 Actual Committed Capacity. The Actual Committed Capacity for the purposes of this Agreement is __________ kW and shall not deviate from the Anticipated Committed Capacity by the greater of one MW or 10 percent of the Anticipated Committed Capacity. The QF elects to receive, and KUA agrees to commence calculating, capacity payments in accordance with this Agreement starting with the first billing month following commerical operation of the Facility.

4.2.3 Capacity Payments. KUA agrees to pay the QF for firm capacity from the Facility in accordance with the rates and provisions contained in Rate Schedule CG-2, as may be amended from time to time.

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

Notwithstanding the foregoing, no capacity payments shall be made if the QF fails to comply with the provisions of this Agreement and Rate Schedule CG-2.

Section 5. Electricity Production Schedule

During the term of this Agreement, the QF agrees, at its cost, to:

(A) Provide KUA, by an annual date specified by KUA preceding each fiscal year (October 1 through September 30) or at other times as may be requested, an estimate of the amount of electricity to be generated by the

Facility and delivered to KUA for each month of the fiscal 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) Coordinate the delivery of its generation output and its scheduled Facility outages with KUA and other utilities as appropriate;

(D) Comply with reasonable requirements of KUA regarding day-to-day and hour-by-hour communications between the Parties relative to the performance of this Agreement;

(E) Provide all necessary information, including, but not limited to, data acquisition for real time telemetry and monitoring of actual generation output of the Facility requested by KUA to implement and administer this Agreement and applicable rate schedules; and

(F) Come off line quickly during emergencies where generation from the Facility would contribute to the overloading of the interconnected utility system.

Section 6. Performance Criteria

The QF, in order to be eligible to receive firm energy and capacity payments, must comply with the following minimum performance criteria:

(i) The QF will begin to deliver energy and capacity no later than the commercial operation date of the Facility.

(ii) The QF agrees to maintain a minimum seventy percent (70%) capacity factor for energy delivered by the QF on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours as defined in Rate Schedule CG-2 during the period, and such calculations shall exclude amounts of hourly output (energy) in excess of five percent (5%) above the Actual Committed Capacity;

(iii) The QF agrees to provide monthly generation estimates by an annual date specified by KUA for the next fiscal year;

(iv) The QF agrees to promptly update the yearly generation schedule when any changes are determined necessary;

(v) The QF agrees to reduce generation or take other appropriate action as requested by KUA for safety reasons or to preserve system integrity;

(vi) The QF agrees to coordinate the delivery of its generated output and scheduled outages with KUA and other utilities as appropriate;

(vii) The QF agrees to comply with KUA's reasonable requests regarding daily or hourly information and communications requirements;

(viii) The QF agrees that it is not entitled to receive capacity payments until the QF has attained commercial in-service status. The commercial in-service date of the QF is defined as the first day of the month following the successful completion of the QF maintaining an hourly kilowatt output, as metered at the point of interconnection with KUA, equal to or greater than the QF's Actual Committed Capacity for a 24-hour test period;

(ix) The QF agrees to coordinate the selection of the above described test period and operation of its facility during such test period with KUA in order to ensure that the performance of the QF during the 24-hour test period is reflective of the anticipated day-to-day operation of the QF;

(x) The QF agrees that the maximum hourly output of its facility shall not exceed the Actual Committed Capacity as defined in Section 4.2.2 by more than five percent (5%);

(xi) The QF agrees that the Facility will be able during emergencies to perform as follows: (a) quickly coming on line, (b) quickly adjusting generation output, (c) remaining in operation and connected to the interconnected utility system, and (d) quickly coming off line where generation from the Facility would contribute to the overloading of the interconnected utility system;

(xii) The QF agrees, since fuel supply is a major factor in the delivery of a reliable supply of capacity and energy from the Facility, to maintain an adequate and reliable supply of primary fuel during the term of this Agreement with backup fuel storage or supplementary fuel supply as deemed appropriate and provide pertinent information, including contract documents, upon request by KUA;

(xiii) The QF agrees to any additional criteria reasonably required by KUA related to the delivery of firm energy and capacity by the QF during KUA's daily and seasonal peak periods; and

(xiv) If the QF's continued operation depends on the sale of thermal energy, the QF agrees to maintain contracts for sale of such during the term of this Agreement and agrees to provide pertinent information, including contract documents, upon request by KUA.

(xv) The QF agrees to supply Firm Capacity at least at the levels and schedule which would have been provided by the Avoided Resource if KUA had not agreed to purchase capacity and energy from the QF.

<u>Section 7</u>. <u>Failure to Meet Performance Criteria</u>

The QF's failure to meet the Performance Criteria in any month may result in no capacity payment by KUA to the QF for such month. Additionally, in the event the QF fails to supply power and energy in accordance with this agreement and Rate Schedule CG-2 the QF shall pay the positive difference, if any, between the actual cost of capacity and energy purchased by KUA less the cost to KUA if such capacity and energy had been supplied to KUA by the QF under Rate Schedule CG-2.

Section 8. Default

8.1 Should any of the following conditions exist, KUA shall have the right to declare the QF in default under this Agreement:

(i) The QF ceases all electric generation for twelve (12) consecutive months;

(ii) After ________________, 19___ (month in which capacity payments commence), the QF fails to maintain a seventy percent (70%) capacity factor on a 12-month rolling average basis for total hours or fails to maintain and eight-five percent (85%) capacity factor on a 12-month rolling average basis for on-peak hours for 24 consecutive months;

(iii) The QF ceases the conduct of active business; or if proceedings under the Bankruptcy Act or insolvency laws shall be instituted by or for or against the QF; or if a receiver shall be appointed for the QF or any of its assets or properties; or if any part of the QF shall be attached, levied upon, encumbered, pledged, seized, or taken under any judicial process and such proceedings shall not be vacated or fully stayed within thirty (30) days thereof; or if the QF shall make an assignment for the benefit of creditors or admit in writing its inability to pay its debts as they become due;

(iv) The QF fails to give proper assurance of adequate performance as specified under the Agreement within thirty (30) days after KUA, with reasonable grounds for insecurity, has requested in writing such assurance; and

(v) The QF materially fails to perform as specified under this Agreement or Rate Schedule CG-2.

8.2 The Parties agree that any default by the QF as defined in this Section will result in substantial injury to KUA, but that a general amount for damages arising from such failures cannot be predetermined. Therefore, the Parties agree that if the QF should default under the terms of this Section, the QF shall pay to KUA, as liquidated damages and not as a penalty, the amount of $______________. This provision shall in no way affect any right KUA might have to terminate this Agreement, and KUA's exercise of a right to terminate shall not release the QF from its obligation to pay liquidated damages in the amount set forth in this paragraph. The QF shall post a bond upon its execution of this Agreement in the amount of the liquidated damages set forth herein and in a form acceptable to KUA. Said bond shall secure payment of liquidated damages to KUA in the event of default by the QF.

Section 9. General Provisions

9.1 Permits. The QF hereby agrees 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. KUA hereby agrees, at QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications, or other authority KUA is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

9.2 Indemnification. The QF agrees to indemnify and save harmless KUA and its respective employees, officers, directors, and agents against any and all liability, loss, damage, costs, or expense which KUA and its respective employees, officers, directors, and agents may hereafter incur, suffer, or be required to pay by reason of negligence on the part of the QF in performing its obligations pursuant to this Agreement or the QF's failure to abide by the provisions of this Agreement. To the extent permitted by law, KUA agrees to indemnify and save harmless the QF against any and all liability, loss, damage, cost, or expense which the QF may hereafter incur, suffer, or be required to pay by reason of the finding of an act of negligence on KUA's system committed by KUA in performing its obligations pursuant to this Agreement or KUA's failure to abide by the provisions of this Agreement. The QF agrees to include KUA as an additional insured in any liability insurance policy or policies the QF obtains to protect the QF's interest with respect to QF's indemnity and hold harmless assurances to KUA contained in this Section.

9.3 Renegotiations Due to Regulatory Changes. Notwithstanding anything in this Agreement to the contrary, should KUA at any time during the term of this Agreement fail to obtain or be denied the regulatory authorization of any regulatory body which now has or in the future may have jurisdiction over KUA's rates and changes, to recover from its customers all of the payments required to be made to the QF under the terms of this Agreement, or any subsequent amendment to this Agreement, the Parties agree that, at KUA's option, they shall renegotiate this Agreement or any applicable amendment. If KUA exercises such option to renegotiate, KUA shall not thereafter be required to make such payments to the extent KUA's authorization to recover them from its customers is not obtained or is denied. It is the intent of the Parties that KUA's payment obligations under this Agreement or any amendment hereto are conditioned upon KUA's being fully reimbursed for such payments through its Cost of Power Adjustment Clause or other authorized rates or charges. Any amounts initially recovered by KUA from its ratepayers but for which recovery is subsequently disallowed by any regulatory body asserting jurisdiction and charged back to KUA may be set off or credited against subsequent payments made by KUA for purchases from the QF, or alternatively, shall be repaid by the QF.

9.4 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 five 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 causes not within the reasonable control of the Parties affected, including, but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure if it is caused by the negligence or lack of due diligence on the part of the Party attempting to make such claim. The QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with KUA's electric system if the same are rendered inoperable due to actions of the QF, its agents, or force majeure events affecting the Facility or the interconnection with KUA. KUA agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by KUA or its agents.

9.5 <u>Assignment</u>. 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 KUA's prior written approval.

9.6 <u>Disclaimer</u>. In executing this Agreement, KUA 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 the QF or any assignee of this Agreement.

9.7 <u>Notification</u>. For purposes of making any and all nonemergency oral and written notices, payments, or the like required under the provisions of this Agreement, the Parties designate the following to be notified or to whom payment be sent until such time as either Party furnishes the other Party written instructions to contact another individual.

For the QF:

____

____

____________________ Telephone ________________

For KUA:

____

____

____________________ Telephone ________________

9.8 Tax Exemption. KUA shall not be required to take any action under this Agreement if such action, in the opinion of KUA, would have an adverse effect on the tax-exempt status of KUA's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

9.9 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida and any unresolved disputes, if litigated, shall be filed with the appropriate Florida courts.

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 KUA's published Rate Schedule CG-2 as approved and amended from time to time. 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 HEREOF, the QF and KUA have executed this Agreement the day and year first above written.

Attested:

By:____________________________

Qualifying Facility

By:____________________________
Authorized Officer

Attested:

By:____________________________
Secretary

Kissimmee Utility Authority

By:____________________________
Chairman

Approved as to form and correctness:

____
Attorney

PARALLEL OPERATION AGREEMENT WITH QUALIFYING FACILITY

Kissimmee Utility Authority (KUA) agrees to interconnect and operate in parallel its electric system with the electric generating facility of ____________________, Qualifying Facility ("QF") subject to the following provisions. The QF and KUA shall collectively be referred hereinafter as the "Parties."

1. Facility

The QF's generating facility, hereinafter referred to as the "Facility," is located at ____. QF intends to have its Facility installed and operational on or about ____________________, 19___. The QF shall provide KUA reasonable prior notice of the Facility's initial operation, and it shall cooperate with KUA to arrange initial deliveries of power to KUA's electric system.

The Facility has been or will be certified as a QF pursuant to Federal Energy Regulatory Commission Rules 202.201 through 292.207 effective March 20, 1980. The QF shall maintain this certification status throughout the term of this Agreement.

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____.

If commercial operation of the Facility is not accomplished by QF before a date agreed upon by the Parties, this Agreement shall be rendered of no force and effect and KUA shall be entitled to take any remedies available to it in accordance with Florida law.

3. Construction Activities

The QF shall provide KUA with written instructions to proceed with construction of the interconnection facilities as described in this Agreement at least 36 months prior to the date on which the Facility shall be completed. KUA agrees to use its reasonable best efforts to complete the interconnection facilities as described in this Agreement within 36 months of receipt of written instructions to proceed.

Upon the Parties' agreement as to the appropriate interconnection design requirements and receipt of written instructions to proceed from the QF, KUA shall design and perform or cause to be designed and performed all of the work necessary to interconnect the Facility with KUA's electric system.

The QF agrees to pay KUA all expenses incurred by KUA to design, construct, operate, maintain, repair, modify, improve, and remove the interconnection with the QF and KUA's electric system as required to integrate the QF's Facility into KUA's electric system. Such costs shall exclude any costs which KUA would otherwise incur if it were not engaged in interconnected operations with the QF, but instead simply provided the electric power requirements of the QF with electricity either generated by KUA or purchased by KUA from another source.

In the event the QF notifies KUA in writing to cease work required for the interconnection before its completion, the QF shall be obligated for all costs incurred up to the date notification is received by KUA including contract cancellation costs.

4. Cost Estimates

Attached hereto as Exhibit A and incorporated herein by this reference is a document entitles "QF Interconnection Cost Estimates." The Parties agree that the cost of the interconnection work contained in Exhibit A is only an estimate of the actual cost to be incurred. The estimated amount will be required to be deposited by the QF to KUA prior to commencement of work on the project. Actual closeout cost of the project may be higher or lower depending upon the completion of the project. To the extent the actual cost is less than the estimate, the difference will be reimbursed to the QF. Likewise, expenses greater than the estimate will be billed to the QF and shall be paid within twenty (20) days of receipt of the invoice.

5. Safety and Technical Requirements

The Parties agree that the QF's interconnection and parallel operation with, and delivery of electricity into, KUA's electric system must be accomplished in accordance with the provisions of Exhibit B entitled "Safety and Technical Standard for Interconnection and Parallel Operation of a Qualifying Facility" attached hereto, and made a part of this agreement.

The QF agrees to require that the Facility operator immediately notify KUA's electric system dispatcher by telephone in the event hazardous or unsafe conditions associated with the Parties' parallel operations are discovered. If such conditions are detected by KUA, KUA will likewise immediately contact the operator of the Facility by telephone. Each Party agrees to take whatever appropriate action is necessary to correct the hazardous or unsafe condition(s).

6. Interconnection Facilities

The interconnection facilities shall include the items identified in Exhibit C, Diagrams and Description of Interconnection Facility, which is made an integral part of this Agreement.

Interconnection facilities in KUA's side of the ownership point with the QF shall be owned, operated, maintained, and repaired by KUA. The QF shall be responsible for the cost of designing, installing, operating, maintaining, repairing, modifying, and improving the interconnection facilities on the QF's side of the ownership point as indicated in Exhibit C. The QF shall be responsible for establishing and maintaining controlled access by third parties to the interconnection facilities.

7. <u>Maintenance and Repair Payments</u>

KUA will separately invoice the QF monthly for all costs associated with the operation, maintenance, repair, modification, and improvement of the interconnection facilities. The QF agrees to pay KUA within twenty (20) days of receipt of each such invoice.

8. <u>Site Access</u>

In order to help ensure the continuous, safe, reliable, and compatible operation of the Facility with KUA's electric system, the QF hereby grants KUA for the period of this Agreement the reasonable right of ingress and egress, consistent with the safe operation of the Facility, over property owned or controlled by the QF to the extent KUA deems such ingress and egress necessary in order to examine, test, calibrate, coordinate, operate, maintain, repair, modify, or improve any interconnection equipment involved in the parallel operation of the Facility and KUA's electric system, including KUA's metering equipment.

9. <u>No KUA Endorsement</u>

In no event shall any KUA statement, representation, or lack thereof, either expressed or implied, relieve the QF of its exclusive responsibility for the Facility. Specifically, any inspection by KUA or its agent(s) of the Facility shall not be construed as confirming or endorsing the Facility's design or its operating or maintenance procedures not as a warranty or guarantee as to the safety, reliability, or durability of the Facility's equipment. KUA's inspection, acceptance, or its failure to inspect shall not be deemed as endorsement of any equipment or procedure of the QF.

10. <u>Responsibility and Liability</u>

KUA shall be responsible for KUA owned facilities. KUA shall indemnify and save the QF harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property by reason of negligence on the part of KUA in performing its obligations pursuant to the interconnection agreement. The QF shall be responsible for the QF's entire system ensuring adequate safeguards for other utility customers, utility personnel and equipment, and for the protection of its own generating system.

The QF shall indemnify and safe KUA harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property (including the QF's generation system and KUA's system) caused by, arising out of, or resulting from:

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

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

3. The QF's negligence or negligence of QF's contractors, agents servants, and employees; or

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

11. Insurance

The QF shall deliver to KUA at least fifteen (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 KUA as an additional name 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 conditions, or otherwise arising out of the performance by the QF or KUA of the terms and conditions of this Agreement.

The policy providing such coverage shall provide public liability insurance, including property damage, with limits in an amount to be determined on a case-by-case basis by KUA, but in no event less than $300,000 for each occurrence. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify KUA thirty (30) days prior to the effective date of cancellation or material change in policy. The QF shall pay all premiums and other charges due so that said policy shall remain in force during the entire period of the interconnection with KUA.

12. 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 causes not within the reasonable control of the Parties affected, including, but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure if it is caused by the negligence or lack of due diligence on the part of the Party attempting to make such claim. The QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with KUA's electric system if the same are rendered inoperable due to actions of the QF, its agents, or force majeure events affecting the Facility or the interconnection with KUA. KUA agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by KUA or its agents.

13. Electric Service to QF

KUA will provide the class or classes of electric service requested by the 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 electricity to KUA.

14. Permits

The QF hereby agrees to obtain any and all governmental permits, certifications, or other authority that the QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. KUA hereby agrees, at the QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications, or other authority KUA is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

15. Notification

For purposes of communications required or authorized by this Agreement, the Parties designate the following representatives:

For the QF: ______________________

____

______________________ Telephone: ______________

For KUA: ______________________

____

______________________ Telephone: ____________

The designation of the above representatives and other pertinent information may be changed by either party at any time upon advance notice provided from one party to the other.

16. Tax-Exemption

KUA shall not be required to take any action under this Agreement if such action, in the opinion of KUA, would have an adverse effect on the tax exempt status of KUA's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

IN WITNESS WHEREOF, QF and KUA executed this Agreement this ____________ day of ______________, 19___.

Attested: Qualifying Facility

By:__________________________ By:__________________________
Authorized Officer

Attested: Kissimmee Utility Authority

__________________________ __________________________

By:__________________________ By:__________________________
Secretary Chairman

EXHIBIT A

<u>QUALIFYING FACILITY INTERCONNECTION COST ESTIMATES</u>

INTENTIONALLY LEFT BLANK

EXHIBIT B

SAFETY AND TECHNICAL STANDARDS FOR PARALLEL OPERATION OF A QUALIFYING FACILITY

INTENTIONALLY LEFT BLANK

EXHIBIT C

DIAGRAMS AND DESCRIPTION OF INTERCONNECTION FACILITY
INTENTIONALLY LEFT BLANK

Code ; Contract [illegible]

DRAFT Pat/Dova

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A QUALIFYING FACILITY LESS THAN 75 MW INTERCONNECTING DIRECTLY WITH THE TRANSMISSION OF DISTRIBUTION SYSTEM OF A CITY WHICH IS A MEMBER OF FMPA'S ALL-REQUIREMENTS PROJECT

This Agreement is made and entered into this _______ day of ____________________, 19___, among Florida Municipal Power Agency (hereinafter referred to as FMPA), City of ____________________, (hereinafter referred to as the City), and ____, (hereinafter referred to as the QF).

WITNESSETH:

WHEREAS, QF, being certified as such and less than 75 MW maximum generation, desires to sell, and FMPA desires to purchase, firm electricity to be generated by the QF and made available to FMPA; and

WHEREAS, the QF has signed an Interconnection Agreement and FMPA and the City are willing to permit the QF to be interconnected and operated in parallel with the City's electric system, so that the QF will be able to deliver to FMPA such energy produced by the QF as will be sold to FMPA. The QF, City and FMPA shall hereinafter be identified as the Parties.

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

ARTICLE 1. Facility

The QF contemplates installing and operating a _______ KVA generator located at ____ ____________________. The generator is designed to produce a maximum of ________________ kilowatts of electricity at an 85% lagging to 85% leading power factor.

The facility has been certified as a qualifying facility pursuant to the Regulations of the Federal Energy Regulatory Commission, and shall maintain the qualifying status throughout the term of this Contract. The facility shall be designed and constructed by the QF or its agents at the QF's sole expense.

ARTICLE 2. Term of the Contract

Except as otherwise provided herein or in the Interconnection Agreement, this contract shall begin immediately upon its execution by the Parties and shall end at 12:01 a.m., ____________________ 20___.

FMPA's avoided capacity may be a generating unit, partial requirements purchases, or a purchase from another utility. In order to receive capacity payments, the QF must execute this contract least eight years before the in-service date of FMPA's planned generating unit and/or reduced partial requirements demand purchase takes place.

If the construction and commercial operation of the facility are not accomplished by the QF at least two years prior to the designated commercial operation date of FMPA's avoided generating unit or if applicable, two years prior to the effective date of reduced partial requirements demand, FMPA's obligations under this Contract shall be rendered of no force and effect, and FMPA shall be entitled to take any remedies available to it in accordance to Florida law.

Upon termination or expiration of this Contract, the Parties shall be relieved of their obligations under this Contract except for the obligation to pay each other monies under this Contract, which obligation shall survive termination or expiration.

ARTICLE 3. Purchase of Capacity and Energy by FMPA

Commencing on the Contract in-service date the QF shall sell and arrange for delivery of the committed capacity to FMPA and FMPA agrees to purchase, accept, and pay for the committed capacity made available to FMPA and which FMPA is able to receive at the point of interconnection in accordance with the terms and conditions of this Contract.

FMPA will make reasonable provisions to purchase firm energy from the QF, but FMPA will not make or accept such purchases of as-available energy from the QF to the extent such purchases will jeopardize the integrity and/or reliability of the City's system or result in costs greater than those which FMPA would incur if it did not make the purchases, but instead generated an equivalent amount of energy itself.

ARTICLE 4. Payment for Electricity Produced by QF

4.1 **Energy.** FMPA agrees to pay the QF for energy produced by the Facility and delivered to FMPA in accordance with the rates and procedures contained in Appendix B and as may be amended from time to time.

Prior to the in-service date of FMPA's Avoided Resource of avoided purchase QF will receive energy payments based on FMPA's actual hourly avoided energy costs. Beginning on the in-service date of FMPA's Avoided Resource of avoided purchases QF's energy payments will be based on the lesser of FMPA's actual avoided hourly energy costs or the fuel costs of FMPA's Avoided Resource (or energy cost of purchase, if purchase is avoided) as defined in with such comparison to be made hourly. Appendix B may be amended from time to time.

4.2 **Capacity.**

4.2.1 **Anticipated Committed Capacity.** QF expects to sell approximately ____________ kW of capacity, beginning on or about ______________ 19___.

QF may finalize its Anticipated Committed Capacity after initial facility testing, and specify when capacity payments are to begin, by completing Section 4.2.2 at a later time. QF must complete Paragraph 4.2.2 at least two years prior to the designated in-service date of FMPA's Avoided Resource or purchase in order to be entitled to any capacity payments pursuant to this Agreement.

4.2.2 Actual Committed Capacity. The Actual Committed Capacity by QF for the purpose of this Agreement is __________kW and shall not deviate from the Anticipated Committed Capacity by the greater of one MW or 10% of the Anticipated Committed Capacity. QF elects to receive, and FMPA agrees to commence calculating capacity payments in accordance with this Agreement starting with the first billing month following ______________, 19___. This date must be at least two years prior to the commercial operation date of the avoided resource or two years prior to the reduction in purchases, whichever is applicable.

4.2.3 Capacity Payments. QF chooses to receive (early or normal) capacity payments from FMPA.

At the end of each billing month, beginning with the billing month specified in Section 4.2.2 and ending with the date specified in Section 2, FMPA will calculate the most recent twelve-month rolling average capacity factors as established in Section 7 for such month based on QF's Actual Committed Capacity. During the initial twelve month period, this calculation will be based on the months that have transpired since the first billing month. If the capacity factors thus calculated are 70% or more for total hours and 85% or more for on-peak hours, then FMPA 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 reduced for all additional costs directly attributable to the purchase of energy from the QF for a given month will be added to the energy payment for such month and tendered by FMPA to QF as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

Notwithstanding the forgoing, no capacity payments shall be made of the QF fails to comply with the provisions of Article 7 herein.

ARTICLE 5. Electricity Production Schedule

During the term of this Agreement, QF agrees at its cost to:

(a) Provide FMPA by March 1 preceding each fiscal year (October 1 through September 30) or at other times as may be requested, an estimate of the amount of electricity to be generated by the Facility and delivered to FMPA for each month of the fiscal 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

(c) Coordinate the delivery of its generation output and its scheduled Facility outages with FMPA and other utilities as appropriate; By October 31 of each calendar year, FMPA shall notify the QF in writing whether the requested scheduled maintenance periods in the detailed plan are acceptable. If FMPA cannot accept any of the requested scheduled maintenance periods, FMPA shall advise the QF of the time period closest to the requested period(s) when the outage(s) can be scheduled. QF shall only schedule outages during periods delayed.

(d) Comply with reasonable requirements of FMPA regarding day-to-day and hour-by-hour communications between the parties relative to the performance of the Agreement;

(e) Provide all necessary information, including but not limited to data acquisition for real time telemetry and monitoring of actual generation output of the Facility, requested by FMPA to implement and administer this Agreement and applicable rate schedules; and

(f) Adjust reactive power flow in the interconnection as may be reasonably required by FMPA.

(g) Come off line quickly during emergencies where generation from the facility would contribute to the overloading of the interconnected utility system.

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

The QF's payment option choice pursuant to Article 4.2.3 may result in early payment by FMPA for capacity delivered. The parties recognize that such capacity payments paid prior to the in-service date of FMPA's Avoided Resource or reduced purchase are in the nature of Early Payments for a future capacity benefit to FMPA. To ensure that FMPA will receive a capacity benefit for which early 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:

FMPA shall establish a Capacity Account. Amounts shall be credited to the Capacity Account each month prior to the in-service date of FMPA's Avoided Resource of reduced purchase equal to the amount of FMPA's capacity payments made to the QF pursuant to QF's chosen payment option. The monthly balance in the Capacity Account shall accrue interest at an annual rate of ________% (equal to the annual discount rate used in developing the early payment of QF).

Commencing on the in-service date of FMPA's Avoided Resource or reduced purchase, there shall be debited from the Capacity Account each month 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 FMPA would have paid for capacity in that month if the QF had elected to begin receiving payment on the, in-service date of FMPA's Avoided Resource or reduced purchase, minus the monthly capacity payment FMPA makes to QF pursuant to the capacity payment option chosen by QF in Article 4.2.3.

The QF shall owe FMPA and be liable for the outstanding balance

ARTICLE 7. Completion Security

7.1 The QF shall provide FMPA either (i) unconditional, irrevocable direct pay letter(s) of credit issued by bank(s) acceptable to FPL in form and substance acceptable to FMPA [including, but not limited to, a provision for automatic renewals through ________________, 199__ and sixty days' prior written notice by the issuing bank(s) to FMPA of the issuing bank(s) intention not to renew the letter(s) of credit, and a provision that, upon receipt of such notice, FMPA may draw upon the letter(s) of credit in full of (ii) cash. Such letters of credit of cash shall be in the amount of ______________________ ________________ Dollars ($________________) [$20 per kW] to assure completion of the Facility by the date specified in Article 4.2.2, and shall be provided or paid to FMPA within ninety days of the execution of the Contract.

7.2 If the commercial operation date does not occur on or before the date specified in Article 4.2.2, then, commencing on such date, and continuing the first calendar day of each calendar month for five calendar months or until the commercial operation date, FMPA shall retain 20% per calendar month (or portion thereof) of such completion security, or shall be entitled to draw on the letter(s) of credit for such percentage per calendar month. The Parties acknowledge that the injury which FMPA will suffer as a result of delayed availability of committed capacity and energy is difficult to ascertain and that FMPA may accept such sums as liquidated damages or resort to any other remedies which may be available to it under law or in equity. If the commercial operation date occurs prior to the date specified in Article 4.2.2, then the QF shall be entitled to a refund of any remaining completion security.

ARTICLE 8. Performance Security

In order to assure that the QF delivers firm capacity and energy in the amounts and at the times specified in this Contract, FMPA shall require an up-front payment or surety bond in the amount of $20 per kilowatt of committed capacity, or an equivalent assurance of payment, to protect FMPA from the QF's failure to so deliver firm capacity and energy. The specific security for the QF's performance selected for purposes of this Contract is:______ ________________. Such payment, surety or equivalent assurance shall be refunded of released, as applicable, upon demonstration, to FMPA's reasonable satisfaction, over a six-month period following commercial operation, that the Facility can deliver the amounts of capacity and energy specified in this Contract. Absent such timely demonstration, the up-front payment, or the amount secured by the surety bond or equivalent assurance payment, shall be forfeited to FMPA to help defray the costs of replacement power.

ARTICLE 9. Performance Criteria

A QF, in order to be eligible to receive firm energy and capacity payments, must comply with the following minimum performance criteria:

(i) The QF will begin to deliver energy and capacity no later than two years prior to the in-service date of FMPA's Avoided Resource or if applicable, the effective date or reduced demand purchases, and continuing for a period of at least ten years beyond such designated date;

(ii) The QF agrees to maintain a minimum seventy percent (70%) capacity factor for energy delivered by QF on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours as defined in Appendix B during the period, and such calculations shall exclude amounts of hourly output (energy) in excess of 5% above the Actual Committed Capacity

(iii) The QF agrees to provide monthly generation estimates by March 1 for the next fiscal year;

(iv) The QF agree to promptly update the yearly generation schedule when any changes are determined necessary;

(v) The QF agrees to reduce generation or take other appropriate action as requested by FMPA for safety reasons or to preserve system integrity;

(vi) The QF agrees to coordinate the delivery of its generated output and schedule outages with FMPA and other utilities as appropriate;

(vii) The QF agrees to comply with FMPA's reasonable requests regarding daily or hourly information and communications requirements;

(viii) The QF agrees that it is not entitled to receive capacity payments until the QF has attained commercial in-service status. The commercial in-service date of the QF is defined as the first day of the month following the successful completion of the QF maintaining an hourly kilowatt output, as metered at the point of interconnection with the City equal to or greater than the QF's Actual Committed Capacity for a 24-hour test period;

(ix) The QF agrees to coordinate the selection of the above described test period and operation of its facility during such test period with FMPA in order to ensure that the performance of the QF during the 24-hour test period is reflective of the anticipated day-to-day operation of the QF;

(x) The QF agrees that the maximum hourly output of its facility shall not exceed the Actual Committed Capacity as defined in Article 4.2.3 by more than 5%;

(xi) The QF agrees that the Facility will be able during emergencies to perform as follows: (a) quickly coming on line, (b) quickly adjusting generation output, (c) remaining
in operation and connected to the interconnected utility system, and (d) quickly coming off line where generation from the Facility would contribute to the overloading of the interconnected utility system;

(xii) The QF agrees, since fuel supply is a major factor in the delivery of a reliable supply of capacity and energy from the Facility, term of this agreement with backup fuel storage or supplementary fuel supply as deemed appropriate and provide pertinent information, including contract documents, upon request by FMPA;

(xiii) The QF agrees to any additional criteria reasonably required by FMPA related to the delivery of firm energy and capacity by the QF during FMPA's daily and seasonal peak periods; and

(xiv) If the QF's continued operation depends on the sale of thermal energy, the QF agrees to maintain contracts for sale of such during the term of this agreement and agrees to provide pertinent information, including contract documents, upon request by FMPA.

ARTICLE 10. Failure to Meet Performance Criteria

10.1 The QF's failure to meet the Performance Criteria inn any months prior to the designated in-service date of FMPA's Avoided Resource in which the QF does not meet the Performance Criteria, the QF will receive no capacity payment. Commencing with the designated in-service date of FMPA's Avoided Resource, the QF will not only fail to receive a capacity payment, but must also immediately repay to FMPA the difference between what it would have been paid had it elected the normal payment option and what it would have been paid pursuant to the early payment option had it met the Performance Criteria.

ARTICLE 11. Default

11.1 Should any of the following conditions exist, FMPA shall have the right to declare the QF in default under this Agreement:

(i) The Qf ceases all electric generation for twelve (12) consecutive months;

(ii) After _______________, 19___, (month in which capacity payments commenne) the QF fails to maintain a 70% capacity factor on a twelve-month rolling average basis for total hours or fails to maintain an 85% capacity factor on a twelve-month rolling average basis for on-peak hours, for twenty-four consecutive months;

(iii) The QF ceases the conduct of active business; or if proceedings under the Bankruptcy Act or insolvency laws shall be instituted by or for or against QF; or if a receiver shall be appointed for the QF or any of its assets or properties; or if any part of the QF shall be attached, levied upon, encumbered, pledged, seized, or taken under any judicial process and such proceedings shall not be vacated or fully stayed within thirty (30) days thereof; or if the QF shall make an assignment for the benefit of creditors or admit in writing its inability to pay its debts as they become due:

(iv) The QF fails to give proper assurance of adequate performance as specified under the Agreement within thirty (30) days after FMPA, with reasonable grounds for insecurity, has requested in writing such assurance; and

(v) The QF materially fails to perform as specified under this Agreement.

Once this contract is declared to be in default, upon written notice to the QF then the current balance in the Capacity Account shall be paid to FMPA.

11.2 The QF shall provide security to FMPA for payment of the current balance, existing from time to time, of the Capacity Account in the event of default by the QF. Security shall be provided by furnishing a bond or by setting up an escrow account to receive payment of Early Capacity Payments. If a bond is furnished, it shall be written on a company and in a form acceptable to FMPA. The bond shall be furnished at the time of execution of this Agreement by the QF and shall have an effective period coextensive with the terms of this contract. The minimum amount of the bond shall be equal to the balance in the Capacity Account as it may exist from time to time during the term of this Agreement.

If an escrow account is established, an escrow agreement will be executed by the parties in a form acceptable to FMPA. Early Capacity Payments will be paid into an interest-bearing account and will be accumulated by the escrow agent until the designated in-service date of FMPA's avoided resource. After that date, the escrow agent shall make monthly payments to the QF in amounts equal to the Early Capacity Payment Offset Amount calculated pursuant to Article 6 of this Agreement.

11.3 The parties agree that any default by the QF as defined in this Article will result in substantial injury to FMPA but that a general amount for damages arising from such failures cannot be predetermined. Therefore, the parties agree that if the QF should default under the terms of the Article, the QF shall pay to FMPA, as liquidated damages and not as a penalty, the amount of $__________, which is based on ninety-six (96) months of exposure for FMPA and $1.00/kW-month of QF capacity stipulated in Article 4.2 of this contract. This provision shall in no way affect any right FMPA might have to terminate this Agreement, and FMPA's exercise of a right to terminate shall not release the QF from its obligation to pay liquidated damages in the amount set forth in this paragraph. The QF shall post a bond upon its execution of this Agreement in the amount of the liquidation damages set forth herein and in a form acceptable to FMPA. Said bond shall secure payment of liquidated damages to FMPA in the event of default by the QF.

ARTICLE 12. General Provisions

12.1 Permits. QF hereby agrees 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. FMPA hereby agrees, at QF's expense, to use its reasonable efforts to obtain any and all governmental permits, certifications or other authority FMPA is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

12.2 Indemnification and Insurance. QF agrees to requirements stated in Interconnection Agreement.

12.3 Renegotiations Due to Regulatory Changes. Notwithstanding anything in this Agreement to the contrary, should FMPA at any time during the term of this Agreement fail to obtain or be denied the regulatory authorization of any regulatory body which now has or in the future may have jurisdiction over FMPA's rates and charges, 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 FMPA's option, they shall renegotiate this Agreement or any applicable amendment. If FMPA exercises such option to renegotiate, FMPA shall not thereafter be required to make such payments to the extent FMPA's authorization to recover them from its customers is not obtained or is denied. FMPA'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 FMPA's payment obligations under this Agreement or any amendment hereto are conditioned upon FMPA's being fully reimbursed for such payments through its Energy Cost Adjustment Clause or other authorized rates or charges. Any amounts initially recovered by FMPA from its ratepayers but for which recovery is subsequently disallowed by any regulatory body asserting jurisdiction and charged back to FMPA may be set off or credited against subsequent payments made by FMPA for purchases from the QF, or alternatively, shall be repaid by the QF.

12.4 Force Majeure. If either Party shall be unable, by reason 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 causes not within the reasonable control of the Parties affected, including but not limited to, 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, pestilence, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however, that no occurrences may be claimed to be a force majeure 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 FMPA's electric 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 FMPA. FMPA agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnection are caused by FMPA or its agents.

12.5 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 FMPA's prior written approval.

12.6 Disclaimer. In executing this Agreement, FMPA 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.

12.7 Communications. Any non-emergency or operational notice, request, consent, payment or other communication made pursuant to this Agreement to be given by one Party to the other Party shall be in writing, either personally delivered or mailed to the representative of said other Party designated in this section, and shall be deemed to be given when received. Notices and other communications by the Company to the QF shall be addressed to:

____
____
____
____
____

Notices to the Company shall be addressed to:

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, FL 32809

Notices to the City shall be addressed to:

____
____
____
____
____

Communications made for emergency or operational reasons may be made to the following persons and shall thereafter be confirmed promptly in writing.

To The Company: __________________
Title: ___________________________
Telephone: _______________________
Telecopier: ______________________

To The City: ______________________
Title: ______________________
Telephone: ______________________
Telecopier: ______________________

Either Party may change its representatives named in this section by prior written notice to the Party.

The Parties' representatives designated above shall have full authority to act for their respective principals in all technical matters relating to the performance of this Agreement. However, they shall not have the authority to amend, modify, or waive any provision of this Agreement.

12.8 Tax Exemption. FMPA shall not be required to take any action under this Agreement if such action, in the opinion of FMPA, would have an adverse effect on the tax-exempt status of FMPA's indebtedness within the meaning of the Internal Revenue Code of 1954, as amended, or its successor, and the applicable U.S. Treasury Regulations promulgated thereunder.

12.9 Applicable Law. This Agreement shall be governed by and constructed in accordance with the laws of the State of Florida and any unresolved disputes if litigated, shall be filed with the appropriate Florida Courts.

12.10 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.

12.11 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.

12.12 Incorporation of Rate Schedule. The Parties agree that this Agreement shall be subject to all of the provisions contained in FMPA's Appendix B and amended from time to time.

12.13 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, the Parties have caused this Agreement to be executed by their duly authorized representatives on the day and year first above written.

The Qualifying Facility:

By: ______________________________

Title: ______________________________

Date: ______________________________

ATTEST:

____

Florida Municipal Power Agency:

By: ______________________________

Title: ______________________________

Date: ______________________________

ATTEST:

____

The City:

By: ______________________________

Title: ______________________________

Date: ______________________________

ATTEST:

____

APPENDIX B

STANDARD RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM QUALIFYING FACILITY RATE SCHEDULE

AVAILABILITY:

This Rate Schedule is available to Qualifying Facilities ("QF") throughout the territory severed by the Florida Municipal Power Agency (FMPA). FMPA will purchase Firm Capacity and Energy offered by any QF within the territory served by FMPA under the provisions of this Rate Schedule or at contract negotiated rates to the extent such purchases are in the best interest of FMPA. FMPA will negotiate and may contract for the purchase of Firm Capacity and Energy from a QF outside FMPA's service territory where such purchases are, as determined by FMPA, in the best interest of FMPA. This Rate Schedule will be available eighty-four (84) months prior to the designated in-service date of FMPA's Avoided Resource, or reduction in partial requirements purchases.

APPLICATION:

This Rate Schedule is applicable to any QF, irrespective of its location, producing capacity and energy for sale to FMPA on a firm basis pursuant to the terms and conditions of this Rate Schedule and FMPA's "Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility", or a separately negotiated contract. Firm Capacity and Energy are capacity and energy produced and sold by a QF pursuant to the Standard Offer Contract or a negotiated contract and subject to contractual provisions as to quantity, time, and reliability of delivery. Criteria for achieving QF status shall be those set out in Federal Energy Regulatory Commission Rules 292.201 through 292.207, effective March 20, 1980.

CHARACTER OF SERVICE:

Purchases within the territory served by the City shall be, at the option of FMPA, single or three phase, 60 hertz, alternating current at standard available voltage.

LIMITATION OF SERVICE:

Purchase under this Rate Schedule are subject to FMPA's need for Firm Capacity and Energy.

Service under this Rate Schedule is limited to those QF's which:

(a) At a point in time not later than eighty-four (84) months prior to the designated in-service date of FMPA's Avoided Resource, execute a Standard Offer Contract for the purchase of Firm Capacity and Energy by FMPA; and

(b) Commit to commence deliveries of Firm Capacity and Energy to FMPA no later than two years before the designated in-service date of FMPA's Avoided Resource and to continue such deliveries through at least ten years beyond the designated in-service date of FMPA's Avoided Resource.

In addition to the above, an option for early capacity payments shall not exceed eighty-four (84) months prior to the designated in-service date of FMPA's Avoided Resource.

RATES FOR PURCHASES BY FMPA:

Firm Capacity and Energy are purchased at a unit cost, in dollars per kilowatt per month and cents per kilowatt hour, resepctively, based on the value of deferring additional capacity resource(s) for FMPA.

A. Firm Capacity Rates

Two options, A and B, as set forth below, are available for payment for Firm Capacity which is produced by the QF and delivered to FMPA. The QF may select either of two payment options: (A) Normal Payment of (B) Early Payment. Option A or B, once selected by the QF, shall remain in effect for the term of the contract between the QF and FMPA. Normal and early payment schedules contain the monthly rate per kilowatt of Firm Capacity the QF has contractually committed to deliver to FMPA and are based on a minimum contract term which extends ten (10) years beyond the designated in-service date of FMPA's Avoided Resource.

Payment schedules are based on the value of a year-by-year deferral of FMPA's Avoided Resource, or partial requirements reduction.

The QF shall select the month and year in which the delivery of Firm Capacity and Energy to FMPA is to commence (must commence at least two years before the designated in-service date of FMPA's Avoided Resource) and capacity payments are to start. FMPA will provide the QF 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.

B. Energy Rates

1. Payment Prior to the designated in-service date of FMPA's Avoided Resource:
The energy rate in cents per kilowatt-hour ($/kWh) shall be based on FMPA's actual hourly avoided energy costs which are calculated by FMPA. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for losses reflecting delivery to the appropriate location on FMPA's electric system. When transactions with other utilities takeplace, the incremental costs are calculated after purchases from other utilities or before sales to other utilities.

The calculation of payments to the QF 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 purchases by FMPA for that hour.

2. **Payments Starting on the designated in-service date of FMPA's Avoided Resource:**

The energy rate in cents per kilowatt-hour ($/kWh), shall be the lesser of an hour-by-hour comparison of: (a) FMPA's actual avoided hourly energy costs, or (b) FMPA's Avoided Resource's applicable fuel costs, including identifiable variable operation and maintenance expenses.

Calculation of payments to the QF shall be based on the sum, over all hours of the billing period, of the product of each hours' appropriate avoided cost (Item (a) or Item (b) in the preceding paragraph) times the purchase by FMPA for that hour. All purchases shall be adjusted for losses from the point of metering to the appropriate location on FMPA's electric system. In the case of item (a) in the preceding paragraph, when transactions with other utilities take place, the incremental costs are calculated after purchases from other utilities or before sales to other utilities.

PERFORMANCE CRITERIA:

Payments for firm capacity are subject to the QF's ability to comply with and maintain the performance criteria set forth in Standard Offer Contract and as follows:

A. Commercial In-Service Date

Capacity payments shall not commence until the QF has obtained and demonstrated commercial in-service status. The commercial in-service date of a QF shall be defined as the first day of the month following the successful demonstration of the QF maintaining an hourly kilowatt (kW) output, as metered at the point of interconnection with FMPA, equal to or greater than the QF's Actual Committed Capacity for a test period as set forth in the Standard Offer Contract. A QF shall coordinate the selection of the test period and operation of its facility during such test period with FMPA to insure that the performance of the QF during this test period is reflective of the anticipated operation of the QF.

B. Capacity Factor

Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly by FMPA inn accordance with the capacity payment rate option(s) selected by the QF and subject to the provision that the QF maintains a minimum seventy percent (70%) capacity factor on a 12-month rolling average basis for the total hours and a minimum eighty-five percent (85%) capacity factor on a 12-month rolling average basis for the on-peak hours. Failure to achieve these capacity factors shall result in the QF's forfeiture of payments for Firm Capacity during the month in which such failure occurs. Where early capacity payment option has been elected and starting with the month of March 1991 (the first month the QF is eligible for such early capacity payments), failure of the QF to maintain capacity factors stated above shall also result in payments by the QF to FMPA. The amount of such payments shall be equal to the difference between: (1) what the QF would have been paid had it elected the normal payment option starting on the designated in-service date of FMPA's Avoided Resource; and (2) what the QF would have been paid pursuant to the early payment option had it maintained the capacity factor performance criteria.

All capacity payments made by FMPA prior to the designated in-service date of FMPA's Avoided Resource or partial requirements reduction, are considered "early payments." The owner and/or operator of the QF, as designated by FMPA, shall secure its obligation to repay, with interest, the cumulative amount of early capacity payments in the event the QF defaults under the terms of its Standard Offer Contract with FMPA. FMPA will provide monthly summaries of the total outstanding balance of such security obligations. The types of security instruments which are acceptable to FMPA are indicated in Appendix A.

C. Additional Criteria

1. The QF shall provide to FMPA prior to March 1, for the next fiscal year or at other times requested by FMPA, monthly generation estimates;

2. The QF shall promptly update its yearly generation schedule and maintenance schedule as and when any changes are determined necessary;

3. The QF shall agree to reduce generation or take other appropriate action as requested by FMPA for safety reasons or to preserve system integrity;

4. The QF shall coordinate the delivery of its generated output and scheduled outages with FMPA;

5. The QF shall comply with the reasonable requests of FMPA regarding daily or hourly communications;

6. The QF shall provide all necessary information including but not limited to data acquisition for real time telemetry and acquisition of actual generation output of the Facility requested by FMPA to implement and administer this Rate Schedule and other applicable rate schedule(s); and

7. The QF's maximum hourly output shall not exceed the Actual Committed Capacity defined in its Standard Offer Contract by more than five percent (5%).

8. The QF shall adjust reactive power flow in the Interconnection as may be reasonably required by FMPA or the electric utility with which the QF

has signed a Parallel Operation Agreement within the range of 90% leading to 85% lagging power factor unless otherwise provided in the Parallel Operation Agreement.

BILLING OPTIONS:

A qualifying facility, upon entering into a contract for the sale of firm capacity and energy or prior to delivery of as-available energy, shall elect to make either simultaneous purchases from the City and sales to FMPA or net sales to FMPA. Once made, the selection of a billing methodology may only be changed:

1. When a 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 FMPA; or

3. When the qualifying facility is selling as-available energy and has no changed billing methods within the last twelve months; and

4. When the election to change billing methods will not contravene the provisions of any contract between the qualifying facility and FMPA.

(b) If a qualifying facility elects to change billing methods in accordance with this rule, such change shall be subject to the following provisions:

1. Upon at least thirty days advance written notice;

2. Upon the installation by the City of FMPA 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 the City or FMPA of and alteration 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 City 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 FMPA shall be purchase at FMPA's avoided energy and capacity rates, where applicable.

(c) Should a qualifying facility elect a net billing arrangement, the hourly net energy and capacity sales delivered to FMPA shall be purchased at the FMPA's avoided energy and capacity rates, where applicable. Purchases from the City shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

METERING REQUIREMENTS:

QF's within the territory served by the City shall be required to pay all costs associated with meters necessary to measure their energy production.

Hourly recording meters shall be required for all QF's delivering firm energy.

TERMS OF PAYMENT:

A statement covering the charges and payments due the QF shall be prepared and rendered monthly by FMPA, and payment normally will be made by the twentieth business day following the end of the billing period or within ten (10) days of mailing (as defined by postmark), whichever is later. Monthly payments shall be adjusted by:

A. <u>Charges for Additional Services</u>
FMPA will charge and collect for additional services requested by the QF to be provided by FMPA.

B. <u>Interconnection Charge for Non-Variable Utility Expenses</u>
The QF shall bear the cost required for the interconnection facilities including the cost of metering and the costs associated with eliminating any impairment or reduction of the electric power transfer capability of the City's transmission system, resulting from or attributable to the interconnection of the QF.

C. <u>Interconnection Charge for Variable Utility Expenses</u>
The QF shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These expenses include (a) FMPA's inspections of the facilities, and (b) ownership costs of any equipment beyond that which would be required to provide normal electric service to the QF if no sales to FMPA were involved.

D. <u>Taxes and Assessments</u>
The QF shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which FMPA's liable as a result of its purchases of Firm Capacity and Energy produced by the QF.

E. <u>Customer Charges</u>
The QF shall be billed monthly for the costs of meter reading, billing, and other applicable administrative costs.

F. ?
Any additional costs incurred by FMPA or the City as a result of the purchase from the QF

TERMS OF SERVICE:

1. It shall be the QF's responsibility to inform FMPA of any change in its electric generation capability.

2. Any electric service delivered by the City to the QF shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall prevail.

3. A security deposit will be required in accordance with FMPA's rules and regulations and the following:

   a. In the first year of operation, the security deposit should be based upon the singular month in which the QF's projected purchases from the City exceed,, by the greatest amount, the City's estimated purchases from the QF. 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 QF and FMPA should 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 QF exceed the actual sales to FMPA in that month.

4. FMPA shall specify the point of interconnection and voltage level.

5. The QF must enter into an interconnection agreement with FMPA and the City. In most cases, the FMPA Interconnection Agreement will be used; however, special features of the QF or its interconnection with the City's facilities may require modifications to the Interconnection Agreement.

SURETY BOND REQUIREMENTS:

FMPA requires that when early capacity payments are elected, the QF must provide assurance of repayment of early capacity payments in the event the QF is unable to meet the terms and conditions of its contract. Depending on the nature of the QF operation, financial health and solvency, and its ability to meet the terms and conditions of the Standard Offer Contract, one of the following may constitute an equivalent assurance of repayment:

(1) Surety Bond;
(2) Escrow;
(3) Irrevocable Letter of Credit

SPECIAL PROVISIONS:

1. Special contracts deviating from the above standard rate schedule are allowable provided they are agreed to by FMPA.

2. A QF located within the City's service territory may sell Firm Capacity and Energy to a utility other than FMPA when adequate transmission capacity is available on the City's system. In addition, the City will provide transmission wheeling service through its service territory, when adequate transmission capacity exists, for a QF located outside the City's service territory, for delivery of the QF's power to the purchasing utility or to an intermediate utility. When such conditions exist, the City will provide transmission wheeling service to deliver the QF's power to the purchasing utility or to an intermediate utility. In either case, the City will charge for wheeling QF Firm Capacity and Energy.

3. FMPA shall be relieved of its obligation to purchase and pay for electric capacity and energy from a QF when purchases result in higher costs to FMPA than without such purchases, and where service to FMPA's other customers may be impaired by such purchases. On such occasions FMPA shall notify the QF as soon as possible or practical.

Code Contr Stan Inter

DRAFT 4/dana

STANDARD AGREEMENT

FOR

INTERCONNECTION

BY

QUALIFYING FACILITIES

DRAF

1.0 General Background Information

Intent of Guidelines. These Interconnection Guidelines are intended to set forth the basic approach and general guidelines for allowing qualifying cogeneration and small power production facilities ("QF's) to interconnection with the electric utility systems listed below.

Utilities Subject to Guidelines. These guidelines have been adopted by Florida Municipal Power Agency ("FMPA") and the following electric distribution Cities in the State of Florida, all of which are members of FMPA's All-Requirements Project and obtain wholesale electric service from FMPA (the "Cities"):

City of Bushnell
City of Green Cove Springs
City of Jacksonville Beach
City of Leesburg
City of Ocala

2.0 Statement of Policy

It is the policy of FMPA and the Cities: (1) to permit any QF to interconnect with the distribution or transmission system of any City; (2) to permit any QF to sell energy and capacity to FMPA; (3) to permit any QF to purchase supplementary, back-up, maintenance, and interruptible power from a City at rates that are nondiscriminatory, just and reasonable, and in the public interest; and (4) to permit any QF so requesting to wheel its energy and capacity over the distribution or transmission system of a City, to the extent transmission or distribution system capacity is available, to any electric utility purchasing such power -- in each case subject to the other expressed and implied terms and conditions of these Guidelines and other requirements imposed by law. Because these Interconnection Guidelines outline the basic approach that FMPA and the Cities intend to use to fulfill their obligations, FMPA and/or a given City may modify them to the extent necessary if such utility determines that the modification is reasonably necessary.

This policy reflects an integrated approach to implementing FMPA's and the Cities obligations. This approach recognizes the function of FMPA as the wholesale supplier to the Cities and retail service function of individual Cities, while assuring each QF of both a market for its power and any necessary back-up maintenance, supplemental, and interruptible service. This integrated approach is necessary since FMPA is a joint-action agency and the Cities each have a long term contract with FMPA under which FMPA provides all their power and energy requirements. Due to this integrated arrangement, FMPA will purchase power from QF's in the electrical territory of the Cities, while the Cities will supply electrical power to the QF's.

No QF will be permitted to operate in parallel with the electric system of a City without the prior knowledge and approval of such City and without entering into a written contract covering the purchase of power by FMPA or the wheeling of the QF power by a City to another electric utility.

DRAFT

A standard Offer Contract has been developed for the purchase of power by FMPA from QFs. Because the QF will actually be interconnected with a City's system rater than FMPA, this contract form is between FMPA, the City, and the QF. FMPA and the City's may revise the Standard Offer Contract from time to time and in particular circumstances may require modifications to the form or may require an individualized contract tailored to the specific QF and circumstances involved. Subject to these qualifications, FMPA and the Cities will use the Standard Offer Contract attached to these Guidelines.

All sales to QFs shall be made pursuant to separate arrangements between the QF and the City and shall be in accordance with that City's applicable rates, rules and regulations governing retail service and all provisions of law relating to retail service.

If a QF prefers to sell its output to another electric utility, the wheeling arrangements shall be pursuant to separate agreement between the QF and the interconnected City(s). Transmission service to wheel as available energy or firm energy and capacity produced by a QF from the QF to another electric utility shall be available unless the provision of such service would adversely affect the adequacy, reliability or cost of providing electric service to the City's general body of retail and wholesale customers. The QF shall be responsible for the costs associated with providing such transmission service. The rates for such transmission service shall be determined by the City, in accordance with generally accepted ratemaking practices and principles.

3.0 General Principles for Safe and Effective Interconnection

The principles stated herein are the minimum requirements for safe and effective interconnections. These Interconnection Guidelines therefore will serve as a basic guide for interconnection, but additional measures may be required at any time by FMPA or by the City with which a QF is or will be interconnected. These Guidelines may be expanded and modified from time to time. In addition, they may be supplemented or modified in particular circumstances as deemed appropriate by FMPA or by the City with which a QF is or will be interconnected.

3.1 City 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 Agreement;

(d) agrees to pay all costs of interconnection; and

(e) signs an interconnection agreement.

DR...

FMPA and the City shall evaluate each request for interconnection on its own merits and may modify the general standards specified in agreement to reflect the result of such an evaluation.

3.2 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 FMPA shall charge interest on the amount owing at the 30-day commercial paper rate. In any event, neither FMPA nor the City will bear any cost of interconnection.

3.3 Application for Interconnection. A qualifying facility shall not operate generating equipment in parallel with the City's electric system without the prior written consent of the City or FMPA. 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 requirements in watts and bars;

(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 City or FMPA does 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.

3.4 Personnel Safety. 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 City or FMPA, all facilities required for the safe operation of the generation system in parallel with the City's system.

DRAFT

The qualifying facility shall permit the City or FMPA'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 City's or FMPA's approval of isolating devices used by the qualifying facility will be required to ensure that these will comply with the City's or FMPA'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 City's system, shall be be required. The City or FMPA 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 City or FMPA and be capable of being locked in the open position with a City or FMPA padlock. The City or FMPA reserves 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. City or FMPA system emergencies and/or maintenance requirements;

2. Hazardous conditions existing on the qualifying facility's generating or protective equipment as determined by the City or FMPA;

3. Adverse effects of the qualifying facility's generation to the City or FMPA's other electric consumers and/or system as determined by the City or FMPA;

4. Failure of the qualifying facility to maintain any required insurance; or

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.

DRAFT

(b) Responsibility and Liability. The utility and the qualifying facility shall each be responsible for its own facilities. The utility and the qualifying facility shall each be responsible for ensuring adequate safeguards for other utility customers, utility and qualifying facility personnel and equipment, and for the protection of its own generating system. The utility and the qualifying facility 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 utility or qualifying facility, as the case may be. Utility shall refer to both the interconnected City and FMPA.

(c) Insurance. The qualifying facility shall deliver to FMPA and the City, at least fifteen days prior to the start of any interconnection work, a certificate of insurance certifying the qualifying facility's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the qualifying facility as named insured, and the City and FMPA 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 qualifying facility, or caused by operation of any of the qualifying facility's equipment or by the qualifying facility's failure to maintain the qualifying facility's equipment in satisfactory and safe operating condition.

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

The qualifying facility shall pay al premiums and other charges due on said policy and keep said policy in forse during the entire period of interconnection with the City.

DRAFT

3.5 <u>Protection and Operation.</u> 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 in 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.

The City and FMPA reserves the right to perform such tests as it deems necessary to ensure safe and efficient protection and operation of the qualifying facility's equipment.

(a) Loss of Source: The qualifying facility shall provide, or the utility will provide at the qualifying facility's expense, approved protective equipment necessary to immediately, completely, and automatically disconnect the qualifying facility's generation from the City's system in the event of a fault on the qualifying facility's system, a fault of the utility's system, or loss of source on the utility's system. Disconnected must be completed within the time specified by the City in it's standard operating procedure for its electric system for loss of a source on the City's system.

This automatic disconnecting device may be of the manual or automatic reclose type and shall not be capable of reclosing until after service is restored by the City. The type and size of the device shall be approved by the City or FMPA depending upon the installation. Adequate test data or technical proof that the device meets the above criteria must be supplied by the qualifying facility to the City or FMPA. The City or FMPA shall approve a device that will perform the above functions at minimal capital and operating costs to the qualifying facility.

(b) Coordination and Synchronization. The qualifying facility shall be responsible for coorination and sychronization of the qualifying facility's equipment with the City's electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the City's system.

(c) Electrical Characteristics. Single phase generator interconnections with the City are permitted at power levels up to 20 KW. For power levels exceeding 20 KW, a three phase balanced interconnection will normally be required. For the purpose of calculating connected generation, 1 horsepower equals 1 kilowatt. The qualifying facility shall interconnect with the City at the voltage of the available distribution or the transmission line of the utility for the locality of the interconnection, and shall utilize one of the standard connections (single phase, three phase, wye, delta) as approved by the City or FMPA.

The City or FMPA reserves the right to require a separate transformation and/or service for a qualifying facility's generation system, at the qualifying facility's expense. The qualifying facility shall bond all neutrals of the qualifying facility's system to the City's neutral, and shall install a separate driven ground woth a resistance value which shall be determined by the City or FMPA and bond this ground to the qualifying facility's system neutral.

(d) Exceptions. A qualifying facility's generator having a capacity rating that can:

1. produce power in excess of 1/2 of the minimum utility customer requirements of the inter-connected distribution or transmission circuit; or

2. produce power flows approaching or exceeding the thermal capacity of the connected utility distribution or transmission lines or trans-formers; or

3. adversely affect the operation of the utility or other utility customer's voltage, frequency or overcurrent control and protection devices; or

4. adversely affect the quality of service to other utility customers; or

5. interconnect at voltage levels greater than distribution voltages,

will require more complex interconnection facilities as deemed necessary by the City or FMPA.

3.6 <u>Quality of Service.</u> The qualifying facility's generated electricity shall meet the following minimum guidelines:

(a) Frequency. The governor control on the prime mover shall be capable of maintaining the generator output frequency within limits for loads from no-load up to rated output. The limits for frequency shall be 60 hertz (cycles per second), plus or minus an instantaneous variation of less than 1%.

(b) Voltage. The regulator control shall be capable of maintaining the generator output voltage within limits for loads from no-load up to rated output. The limits for voltage shall be the nominal operating voltage level, plus or minus 5%.

(c) Harmonics. The output sine wave distortion shall be deemed acceptable when it does not have a higher content (root mean square) of harmonics than the utility's normal harmonic content at the interconnection point.

(d) Power Factor. The qualifying facility's generation system shall be designed, operated and controlled to provide reactive power requirements from 0.85 lagging to 0.85 leading power factor. Induction generators shall have static capacitors that provide at least 85% of the magnetizing current

DRAFT

requirements of the induction generator field. (Capacitors shall not be so large as to permit self-excitation of the qualifying facility's generator field).

(e) DC Generators. Direct current generators may be operated in parallel with the utility's system through a synchronous inverter. The inverter must meet all criteria in these rules.

3.7 Metering. The actual metering equipment required its voltage rating, number of phases, size, current transformers, potential transformers, number of inputs and associated memory is dependent on the type, size and location of the electric service 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 will be measured separately from power flowing out of the qualifying facility's system.

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

3.8 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 of the qualifying facility were a non-generating customer. These costs shall be paid by the qualifying facility to FMPA for all material and labor that is required. Prior to any work being done by the City or FMPA, FMPA or the City shall supply the qualifying facility 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.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix
by Members
1987-2007

FORT PIERCE AND VERO BEACH
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase
	%	%	%	%	%	%	%	%	%	%	%	%
1987	18.0	4.5	12.1	0.0	9.3	56.1	18.0	4.5	12.1	0.0	9.3	56.1
1988	16.3	17.1	18.8	0.0	9.0	38.8	16.3	17.1	18.8	0.0	9.0	38.8
1989	15.6	16.4	49.4	0.1	8.5	10.0	15.6	16.4	49.4	0.1	8.5	10.0
1990	13.9	16.6	48.8	0.0	8.4	12.3	13.9	16.6	48.8	0.0	8.4	12.3
1991	12.2	24.5	55.1	0.1	8.1	0.0	12.2	24.5	55.1	0.1	8.1	0.0
1992	13.1	24.0	58.3	0.0	4.7	0.0	13.1	24.0	58.3	0.0	4.7	0.0
1993	12.2	23.3	60.0	0.0	4.5	0.0	12.2	23.3	60.0	0.0	4.5	0.0
1994	11.3	22.7	59.0	0.0	7.0	0.0	11.3	22.7	59.0	0.0	7.0	0.0
1995	12.1	22.2	58.2	0.0	7.5	0.0	12.1	22.2	58.9	0.0	6.9	0.0
1996	11.4	21.7	58.1	0.0	8.8	0.0	11.4	21.7	60.1	0.0	6.8	0.0
1997	10.6	21.4	57.2	0.0	10.8	0.0	10.6	34.5	48.8	0.0	6.0	0.0
1998	11.5	21.0	55.1	0.0	12.4	0.0	11.5	37.6	45.2	0.0	5.7	0.0
1999	10.8	20.7	53.7	0.0	14.8	0.0	10.8	37.0	46.5	0.0	5.7	0.0
2000	10.1	20.3	51.6	0.0	18.0	0.0	10.1	36.4	46.6	0.0	6.9	0.0
2001	10.9	20.0	48.5	0.0	20.5	0.0	10.9	35.7	45.5	0.0	7.9	0.0
2002	10.3	19.7	47.2	0.0	22.8	0.0	10.3	35.2	45.1	0.0	9.5	0.0
2003	9.6	19.4	45.1	0.0	25.9	0.0	9.6	34.7	44.6	0.0	11.1	0.0
2004	10.4	19.1	42.6	0.0	27.9	0.0	10.4	34.1	42.6	0.0	12.9	0.0
2005	9.8	18.8	41.2	0.0	30.2	0.0	9.8	33.6	41.3	0.0	15.3	0.0
2006	9.2	18.5	39.4	0.0	33.0	0.0	9.2	33.1	40.0	0.0	17.8	0.0
2007	9.9	18.2	37.2	0.0	34.7	0.0	9.9	32.6	37.8	0.0	19.7	0.0

[1] Includes St. Lucie Units 1 and 2.
[2] Includes Stanton Units 1 and 2.
[3] Includes FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 44
COMPANY/ WITNESS: Guarriello
DATE: 6/19/91

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix
by Members
1987-2007

CITY OF HOMESTEAD
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase
	%	%	%	%	%	%	%	%	%	%	%	%
1987	22.7	33.8	26.6	1.4	15.5	0.0	22.7	33.8	26.6	1.4	15.5	0.0
1988	23.3	54.5	16.1	0.8	5.3	0.0	23.3	54.5	16.1	0.8	5.3	0.0
1989	17.6	55.4	18.5	0.9	7.6	0.0	17.6	55.4	18.5	0.9	7.6	0.0
1990	13.4	46.5	33.6	1.8	4.7	0.0	13.4	46.5	33.6	1.8	4.7	0.0
1991	15.9	51.0	30.2	1.6	1.3	0.0	15.9	51.0	30.2	1.6	1.3	0.0
1992	14.3	50.2	33.8	1.7	0.0	0.0	14.3	50.2	33.8	1.7	0.0	0.0
1993	15.3	49.3	33.6	1.8	0.0	0.0	15.3	49.3	33.6	1.8	0.0	0.0
1994	14.9	48.1	35.1	1.9	0.0	0.0	14.9	48.1	35.1	1.9	0.0	0.0
1995	14.6	47.6	36.1	1.7	0.0	0.0	14.6	47.6	36.1	1.7	0.0	0.0
1996	14.3	36.9	48.5	0.3	0.0	0.0	14.3	46.7	37.3	1.7	0.0	0.0
1997	13.9	33.6	52.4	0.1	0.0	0.0	13.9	68.2	17.1	0.8	0.0	0.0
1998	13.7	33.4	52.8	0.1	0.0	0.0	13.7	71.5	14.2	0.6	0.0	0.0
1999	13.5	33.9	52.6	0.0	0.0	0.0	13.5	71.5	14.3	0.7	0.0	0.0
2000	13.3	33.8	52.9	0.0	0.0	0.0	13.3	70.5	15.5	0.7	0.0	0.0
2001	13.1	33.7	53.1	0.1	0.0	0.0	13.1	69.9	16.5	0.5	0.0	0.0
2002	12.9	33.7	53.1	0.3	0.0	0.0	12.9	68.8	17.8	0.5	0.0	0.0
2003	12.8	33.8	53.1	0.3	0.0	0.0	12.8	68.5	18.3	0.4	0.0	0.0
2004	12.6	33.8	53.1	0.5	0.0	0.0	12.6	67.9	19.1	0.4	0.0	0.0
2005	12.5	34.0	53.2	0.3	0.0	0.0	12.5	67.7	19.4	0.4	0.0	0.0
2006	12.3	33.5	53.3	0.9	0.0	0.0	12.3	66.8	20.3	0.6	0.0	0.0
2007	12.1	33.9	53.2	0.8	0.0	0.0	12.1	66.5	20.9	0.5	0.0	0.0

---

[1] Includes St. Lucie Units 1 and 2.
[2] Includes Stanton Units 1 and 2.
[3] Includes FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix by Members 1987-2007

UTILITY BOARD OF KEY WEST
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear	Coal [1]	Gas	Oil	Firm Purchase [2]	Other Purchase [3]	Nuclear	Coal [1]	Gas	Oil	Firm Purchase [2]	Other Purchase [3]
	%	%	%	%	%	%	%	%	%	%	%	%
1987	0.0	3.0	0.0	51.3	0.0	45.7	0.0	3.0	0.0	51.3	0.0	45.7
1988	0.0	10.4	0.0	24.8	0.0	64.8	0.0	10.4	0.0	24.8	0.0	64.8
1989	0.0	8.0	0.0	24.9	0.0	67.1	0.0	8.0	0.0	24.9	0.0	67.1
1990	0.0	10.8	0.0	24.8	0.0	64.4	0.0	10.8	0.0	24.8	0.0	64.4
1991	0.0	15.2	0.0	38.8	0.0	46.0	0.0	15.2	0.0	38.8	0.0	46.0
1992	0.0	14.6	0.0	38.9	0.0	46.4	0.0	14.6	0.0	38.9	0.0	46.4
1993	0.0	14.2	0.0	49.9	29.4	6.5	0.0	14.2	0.0	49.9	29.4	6.5
1994	0.0	13.7	0.0	51.9	32.8	1.5	0.0	13.7	0.0	51.9	32.8	1.5
1995	0.0	13.3	0.0	49.2	36.2	1.3	0.0	13.3	0.0	49.2	36.2	1.3
1996	0.0	13.1	0.0	47.4	38.2	1.3	0.0	13.1	0.0	47.4	38.2	1.3
1997	0.0	12.8	0.0	45.9	40.2	1.1	0.0	19.8	0.0	48.3	30.4	1.4
1998	0.0	12.5	0.0	44.4	41.9	1.1	0.0	22.1	0.0	44.6	32.2	1.1
1999	0.0	12.3	0.0	42.1	44.7	0.9	0.0	21.6	0.0	43.3	34.0	1.1
2000	0.0	12.0	0.0	39.7	47.5	0.9	0.0	21.1	0.0	40.9	37.0	1.0
2001	0.0	11.7	0.0	38.6	48.8	0.9	0.0	20.7	0.0	39.7	38.6	1.0
2002	0.0	11.5	0.0	49.2	37.6	1.7	0.0	20.3	0.0	48.2	29.9	1.6
2003	0.0	11.3	0.0	51.1	35.7	2.0	0.0	19.9	0.0	52.0	25.8	2.3
2004	0.0	11.1	0.0	49.6	37.4	1.9	0.0	19.5	0.0	49.6	28.9	1.9
2005	0.0	10.9	0.0	47.3	40.2	1.6	0.0	19.2	0.0	48.4	30.6	1.9
2006	0.0	10.7	0.0	46.0	41.7	1.6	0.0	18.8	0.0	46.9	32.4	1.9
2007	0.0	10.5	0.0	44.7	43.3	1.6	0.0	18.5	0.0	44.8	35.1	1.6

[1] Includes Stanton Units 1 and 2.
[2] Includes FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.
[3] Includes FPL Short Term Power, Metro purchases and emergency interchange purchases.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix
by Members
1987-2007

LAKE WORTH UTILITIES
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase
	%	%	%	%	%	%	%	%	%	%	%	%
1987	40.5	3.1	42.4	12.0	2.0	0.0	40.5	3.1	42.4	12.0	2.0	0.0
1988	38.4	12.4	46.6	2.0	0.6	0.0	38.4	12.4	46.6	2.0	0.6	0.0
1989	37.2	12.0	46.9	3.9	0.0	0.0	37.2	12.0	46.9	3.9	0.0	0.0
1990	33.5	12.3	39.1	15.1	0.0	0.0	33.5	12.3	39.1	15.1	0.0	0.0
1991	33.2	18.7	47.6	0.5	0.0	0.0	33.3	18.7	47.6	0.4	0.0	0.0
1992	33.6	18.4	30.2	1.6	16.2	0.0	32.6	18.4	33.0	2.8	13.0	0.0
1993	31.9	18.0	30.0	0.1	20.0	0.0	31.9	18.0	33.5	0.5	16.1	0.0
1994	31.2	17.6	26.3	0.4	24.5	0.0	31.2	17.6	31.1	0.6	19.5	0.0
1995	30.5	17.2	22.1	0.3	29.9	0.0	30.5	17.2	28.0	0.4	23.9	0.0
1996	30.0	16.9	17.5	0.1	35.5	0.0	30.0	16.9	23.5	0.2	29.4	0.0
1997	29.4	16.6	13.0	0.1	40.9	0.0	29.4	29.8	10.3	0.2	30.3	0.0
1998	28.8	16.3	8.8	0.1	46.0	0.0	28.8	29.3	7.7	0.0	34.1	0.0
1999	23.0	16.0	6.2	0.7	54.1	0.0	23.0	28.7	6.0	0.7	41.6	0.0
2000	22.6	15.6	6.2	0.8	54.8	0.0	22.6	28.1	6.0	0.7	42.6	0.0
2001	22.4	15.5	5.8	0.8	55.5	0.0	22.4	27.9	5.7	0.7	43.3	0.0
2002	22.2	15.4	5.6	0.6	56.2	0.0	22.2	27.7	5.4	0.6	44.1	0.0
2003	22.1	15.3	5.8	0.6	56.2	0.0	22.1	27.5	5.6	0.6	44.2	0.0
2004	21.8	15.1	5.5	0.8	56.8	0.0	21.8	27.2	5.4	0.7	44.9	0.0
2005	21.6	15.0	5.3	0.7	57.4	0.0	21.6	27.0	4.6	0.6	46.2	0.0
2006	21.5	14.9	2.7	0.4	60.5	0.0	21.5	26.8	2.0	0.3	49.4	0.0
2007	21.5	14.9	0.6	0.0	63.0	0.0	21.5	26.7	0.4	0.5	51.3	0.0

[1] Includes St. Lucie Units 1 and 2.
[2] Includes Stanton Units 1 and 2.
[3] Includes FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix
by Members
1987-2007

CITY OF STARKE
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear	Coal	Gas	Oil	Firm Purchase [1]	Other Purchase	Nuclear	Coal	Gas	Oil	Firm Purchase [1]	Other Purchase
	%	%	%	%	%	%	%	%	%	%	%	%
1987	0.0	0.0	22.2	1.9	75.9	0.0	0.0	0.0	22.2	1.9	75.9	0.0
1988	0.0	0.0	5.5	1.8	92.7	0.0	0.0	0.0	5.5	1.8	92.7	0.0
1989	0.0	0.0	4.8	1.6	93.6	0.0	0.0	0.0	4.8	1.6	93.6	0.0
1990	0.0	0.0	5.1	1.7	93.2	0.0	0.0	0.0	5.1	1.7	93.2	0.0
1991	0.0	53.4	0.0	9.8	36.8	0.0	0.0	53.4	0.0	9.8	36.8	0.0
1992	0.0	51.7	0.0	9.5	38.8	0.0	0.0	51.7	0.0	9.5	38.8	0.0
1993	0.0	50.2	0.0	9.2	40.7	0.0	0.0	50.2	0.0	9.2	40.7	0.0
1994	0.0	48.7	0.0	8.9	42.4	0.0	0.0	48.7	0.0	8.9	42.4	0.0
1995	0.0	47.3	0.0	8.7	44.1	0.0	0.0	47.3	0.0	8.7	44.1	0.0
1996	0.0	45.9	0.0	8.4	45.7	0.0	0.0	45.9	0.0	8.4	45.7	0.0
1997	0.0	44.6	0.0	8.2	47.2	0.0	0.0	54.5	0.0	8.2	37.2	0.0
1998	0.0	43.4	0.0	9.1	47.5	0.0	0.0	53.1	0.0	9.1	37.8	0.0
1999	0.0	42.3	0.0	6.6	51.1	0.0	0.0	51.7	0.0	6.6	41.7	0.0
2000	0.0	12.4	0.0	8.7	78.9	0.0	0.0	21.5	0.0	8.7	69.7	0.0
2001	0.0	12.1	0.0	6.3	81.6	0.0	0.0	21.0	0.0	6.3	72.7	0.0
2002	0.0	11.8	0.0	7.0	81.2	0.0	0.0	20.5	0.0	7.0	72.5	0.0
2003	0.0	11.5	0.0	5.1	83.4	0.0	0.0	20.0	0.0	5.1	74.9	0.0
2004	0.0	11.2	0.0	5.8	83.0	0.0	0.0	19.6	0.0	5.8	74.7	0.0
2005	0.0	11.0	0.0	4.2	84.9	0.0	0.0	19.1	0.0	4.2	76.7	0.0
2006	0.0	10.7	0.0	4.7	84.5	0.0	0.0	18.7	0.0	4.7	76.6	0.0
2007	0.0	10.5	0.0	5.3	84.2	0.0	0.0	18.3	0.0	5.3	76.4	0.0

[1] Includes FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.

Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Witness: Robert C. Williams
Nicholas P. Guarriello
Late Filed Exhibit No. 44
Description: FMPA Fuel Mix
by Members
1987-2007

ALL-REQUIREMENTS PROJECT
FUEL MIX
1987-2007

	Without Stanton 2						With Stanton 2					
	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase	Nuclear [1]	Coal [2]	Gas	Oil	Firm Purchase [3]	Other Purchase
	%	%	%	%	%	%	%	%	%	%	%	%
1987	6.6	18.9	10.8	3.2	33.3	27.1	6.6	18.9	10.8	3.2	33.3	27.1
1988	10.6	16.4	13.6	2.6	16.4	40.5	10.6	16.4	13.6	2.6	16.4	40.5
1989	7.7	27.1	10.5	2.6	18.9	33.1	7.7	27.1	10.5	2.6	18.9	33.1
1990	8.4	17.3	11.8	1.4	24.7	36.4	8.4	17.3	11.8	1.4	24.7	36.4
1991	9.1	15.3	30.7	1.4	43.6	0.0	9.1	15.3	30.7	1.4	43.6	0.0
1992	7.0	11.3	28.1	1.1	52.5	0.0	7.0	11.3	28.1	1.1	52.5	0.0
1993	8.3	7.8	33.0	1.2	49.6	0.0	8.3	7.8	33.0	1.2	49.6	0.0
1994	6.7	7.6	31.7	1.1	52.9	0.0	6.7	7.6	31.7	1.1	52.9	0.0
1995	7.5	7.3	25.7	1.0	58.5	0.0	7.5	7.3	25.7	1.0	58.5	0.0
1996	6.3	7.1	23.4	0.9	62.3	0.0	6.3	7.1	23.4	0.9	62.3	0.0
1997	7.3	6.9	21.4	0.8	63.6	0.0	7.3	12.5	21.8	0.7	57.7	0.0
1998	5.7	6.7	21.2	0.8	65.6	0.0	5.7	12.2	21.9	0.8	59.5	0.0
1999	6.9	6.5	19.1	0.7	66.8	0.0	6.9	11.8	19.7	0.7	60.8	0.0
2000	5.6	6.3	18.8	0.6	68.6	0.0	5.6	11.5	19.5	0.7	62.7	0.0
2001	6.3	6.2	17.1	0.6	69.8	0.0	6.3	11.2	17.6	0.6	64.2	0.0
2002	5.3	6.0	14.0	0.6	74.1	0.0	5.3	10.9	14.5	0.6	68.7	0.0
2003	6.2	5.9	10.5	0.5	77.0	0.0	6.2	10.7	10.9	0.5	71.7	0.0
2004	4.9	5.7	7.7	0.4	81.2	0.0	4.9	10.4	8.0	0.5	76.2	0.0
2005	5.9	5.6	6.1	0.3	82.0	0.0	5.9	10.2	6.3	0.3	77.2	0.0
2006	4.9	5.5	5.4	0.0	84.2	0.0	4.9	9.9	5.6	0.0	79.6	0.0
2007	5.5	5.3	0.7	0.0	88.4	0.0	5.5	9.7	0.9	0.0	83.9	0.0

[1] Includes St. Lucie Units 1 and 2.
[2] Includes Stanton Units 1 and 2.
[3] Includes FPC and FPL Partial Requirements purchases, which is a mix of nuclear, coal, gas, oil and purchases.

Table 1

Electricity Demand, System Capacity, and Intervenors' Proposed Alternatives, 1997

	Winter Peak (MW)	Summer Peak (MW)	Energy (GWh)
Electricity demand, per OUC projections before additional conservation measures which OUC intends to adopt (Ref. p. 1.B.A. .12-21)	1,220	1,141	5,225
Reserve Margin @ 15%	183	171	
Extra demand allowance re winter peak (p. 1.B.11.4-4) (1)	44	-	
System demand per OUC	1,447	1,312	5,225
System Capacity (Ref. p. 1.B. 2.0-4, 1B.2.0-5)	1,401	1,336	(Load factor = 43%
Gap to be filled	46	-	-
Conservation Programs already scheduled to be adopted but not deducted in above demands:			
Interruptible Service (Ref. p. 1B.6.4-12)	4.4	-	n.a.
Commercial Lighting (2)	7.0	2.6	53
Residential Heat Pumps to Replace resistance heat. (Ref. 1B.6.4-14,15)	7.0	.7	3
	18.4	3.3	56
Reintroduce Load Control Measures (3) Considered by OUC but not adopted (Ref. 1B.6.4-1 to1B.6.4-6,1B.6.4-14	14	7	-
Additional ConservatiOnMeasures:			
Residential Lighting Efficiency, Examined and found highly cost-effective by OUC. Ref. 1B.6.3-19 (and see narrative)	1.6	-	5
Residential Time-of-use rates (5)	2.5	2	3
Commercial Window Film (see Narrative)	2	6.7	21
Commercial HVAC Conservation (see narrative)	2	2.8	9.6
Builder Conservation Incentives	1	1	1.3
15% Reserve Margin Applied to above	6.2		
Sum of measures to close "gap"	47.7	n. a.	94

System load factor= 43%

Tsble 2

Electricity Demand, System Capacity, and Intervenors' Proposed Alternatives, 2002
OUC Service Area

	Winter Peak (MW)	Summer Peak (MW)	Energy (GWh)
Electricity demand per OUC projections before additional conservation measures which OUC intends to adopt (Ref. 1B.A. 12-21)	1,350	1,273	6,153
Reserve Margin @ 15%	202	191	
Extra Demand Allowance re winter peak (1)	21	-	
Demand, per OUC	1,573	1,464	6,153
System Capacity	1,401	1,336	
Gap to be filled	172	128	
Conservation Programs already scheduled to be adopted but not deducted above:			
Interruptible Service (Ref. p. 1B.6.4-12)	8.9	8.9	n.a
Commercial Lighting (2)	21.2	8	160
Residential Heat Pumps to Replace resistance heat. (Ref. 1B.6.4-14,15)	11	1	5
Subtotal	41.1	17.9	165
Reintroduce Load Control Measures Considered by OUC but not adopted, and others(3)	60	29	-
Additional Conservation Measures			
Residential Efficient Lighting (4)	6.7	1	20
Residential Time-of-Use Rates (5)	4.6	3.7	5.5
Commercial Window Film (see Narrative)	4.0	13.4	42
Commercial HVAC Conservation (see narrative)	8	33.7	75.4
Builder Efficiency Incentives (see narrative)	6	6	10
Customer Cogeneration	20	20	122
15% Reserve margin applied to above	22	18.7	
Sum of Measures to close "gap"	172	143.4	440

System Load Factor= 47%

A Conservation Alternative to
Stanton Energy Center Unit 2

The Orlando Utilities Commission plans to bring a 440-Megawatt coal plant on line in January, 1997. It would own 330 MW, with the remainder going to the City of Kissimmee (16.9MW) and, through the Florida Municipal Power Agency, to 12 other smaller cities in Florida with municipally-owned electric systems.

The intervenors propose an alternative emphasizing electricity conservation, which would defer the need for this $612 million coal plant for five years. Each element of the alternative plan "buys" electricity more cheaply than it can be bought through constructing a large new generating unit. Indeed, over half of the necessary "saved" electricity is identified in documents prepared by or for OUC itself.

Table 1 shows, for Orlando, the system supply and demand situation in 1997. It shows the need for new capacity as identified by OUC, and then shows the elements of a conservation program which will meet that need. Table 2 shows similar information for the year 2002. Notes to the Tables refer to information taken from OUC documents. These notes and the following narrative show, for each element of the proposed alternative, the lesser costs of the alternatives as compared with building new generating capacity.

The second part of the alternative plan deals with the other cities who would be affected by a decision to defer the construction of Stanton Energy Center Unit 2. Conservation alternatives are listed which show, for each city affected, ways of meeting demands without Stanton 2.

EXHIBIT
OUC 3
6/14/91 KTH

Table 1

Electricity Demand, System Capacity, and Intervenors' Proposed Alternatives, 1997

	Winter Peak (MW)	Summer Peak (MW)	Energy (GWh)
Electricity demand, per OUC projections before additional conservation measures which OUC intends to adopt (Ref. p. 1.B.A. .12-21)	1,220	1,141	5,225
Reserve Margin @ 15%	183	171	
Extra demand allowance re winter peak (p. 1.B.11.4-4) (1)	44	-	
System demand per OUC	1,447	1,312	5,225
System Capacity (Ref. p. 1.B. 2.0-4, 1B.2.0-5)	1,401	1,336	(Load factor = 43%
Gap to be filled	46	-	-
Conservation programs already scheduled to be adopted but not deducted in above demands:			
Interruptible Service (Ref. p. 1B.6.4-12)	4.4	-	n.a.
Commercial Lighting (2)	7.0	2.6	53
Residential Heat Pumps to Replace resistance heat. (Ref. 1B.6.4-14,15)	7.0	.7	3
	18.4	3.3	56
Reintroduce Load Control Measures (3) Considered by OUC but not adopted (Ref. 1B.6.4-1 to1B.6.4-6,1B.6.4-14	14	7	-
Additional ConservatiOnMeasures:			
Residential Lighting Efficiency, Examined and found highly cost-effective by OUC. Ref. 1B.6.3-19 (and see narrative)	1.6	-	5
Residential Time-of-use rates (5)	2.5	2	3
Commercial Window Film (see Narrative)	2	6.7	21
Commercial HVAC Conservation (see narrative)	2	2.8	7.6
Builder-Conservation Incentives	1	1	1.3
15% Reserve Margin applied to above	6.2		
Sum of measures to close "gap"	47.7	n. a.	94

System load factor= 43%

Tsble 2

Electricity Demand, System Capacity, and Intervenors' Proposed Alternatives, 2002
OUC Service Area

	Winter Peak (MW)	Summer Peak (MW)	Energy (GWh)
Electricity demand per OUC projections before additional conservation measures which OUC intends to adopt (Ref. 1B.A. 12-21)	1,350	1,275	6,153
Reserve Margin @ 15%	202	191	
Extra Demand Allowance re winter peak (1)	21	-	
Demand, per OUC	1,573	1,464	6,153
System Capacity	1,401	1,336	
Gap to be filled	172	128	
Conservation Programs already scheduled to be adopted but not deducted above:			
Interruptible Service (Ref. p. 1B.6.4-12)	8.9	8.9	n.a
Commercial Lighting (2)	21.2	8	160
Residential Heat Pumps to Replace resistance heat. (Ref. 1B.6.4-14,15)	11	1	5
Subtotal	41.1	17.9	165
Reintroduce Load Control Measures Considered by OUC but not adopted, and others(3)	60	29	-
Additional Conservation Measures			
Residential Efficient Lighting (4)	6.7	1	20
Residential Time-of-Use Rates (5)	4.6	3.7	5.5
Commercial Window Film (see Narrative)	4.0	13.4	42
Commercial HVAC Conservation (see narrative)	8	33.7	75.4
Builder Efficiency Incentives (see narrative)	6	6	10
Customer Cogeneration	20	20	122
15% Reserve margin applied to above	22	18.7	
Sum of Measures to close "gap"	172	143.4	440

System Load Factor= 47%

Composite Page 3

Notes to Tables 1 and 2

1. OUC, in an apparent inconsistency, brings the following year's winter peak forward one year. (Ref. p. 1B.11.4-6) This is explained as providing for the case in which a January winter peak may occur in the preceding December. Bringing the 1998 winter peak into 1997 triggers the need for new capacity in 1997 in the Table referenced, even when conservation and load control measures are deducted from peak demands. Yet the plant is scheduled for January, 1997, nt December 1997.

2. Commercial lighting programs are highly cost-effective even with the erroneous screening formula which is biased against conservation measures. The 1997 figure is from p. 1B.6.4-15. The 2002 figure accelerates the program and brings the 2005 target forward three years. See also the narrative section on commercial lighting.

3. Load control measures are now used by Florida Power and Light, Florida Power Corp., Tampa Electric and three municipal systems. They are scheduled for introduction Gainesville Lakeland and Tallahassee amont the larger municipal systems during the 1990's. They were not found to reduce the PWRR by OUC because they were not introduced in sufficient measure to defer capacity. (Ref. 1B.11.6-1) Naturally, when the expense of load control is added and no capacity is deferred, toal costs go up, not down. When load control, along with conservation measures, defer capital costs, then load control investments are highly cost-effective.

   We use OUC's figure for 1997. For the year 2002, we use an accelerated program which raaches 30% of customers by that year.

   In addition, we recommend the extension of load consrol measures to residential ~~and commercial~~ pool pumps, and to commercial water heating, cooling and space heating customers whose operations lend themselves to cycling.

   Reaching 30% of customers for the measures reviewed by OUC would reach 50 MW of winter peak demand. (64 MW in 2020 per Tables 1B.11.4-2 and 1B.11.4-3, scaled back for the smaller number of year 2002 residential customers.

   We estimate an additional 10 megawatts, winter peak for adding pool pumps and selected commercial customers to the program. Summer peak reductions are taken in proportion to those shown on p. 1B.6.4-13.- 29 MW

   The winter peak total, 60 MW by 2002, represents 5% of estimated native peak winter demand.

Composite Page 4

Corresponding percentages projected for other utilities are: (for the year 2000, the latest shown) Florida Power and Light 3.8%, Florida Power Corp. 17.5%, TECO, 7.2%, Lakeland 6% and Tallahassee 2.6%. (Source: Florida Electric Power Coordinating group, Inc. 1991 Ten-Year Plan, State of Florida

4. Residential efficient lighting was fiund to be highly cost-effective by OUC but dropped because of its "small impact". (Refs. p 1B.6.3-19 and p. 1B.6.4-10). An error cut the savings effect by half (see narrative). Savings are 350 kwh per participating household per year. Program is accelerated to reach target saturation of 40% of households in 11 years. 2002 savings are 19.6 GWh and winter peak savings of 6.7 MW. The latter is calculated from p. 1B.6.3-24, corrected. OUC does not show summer peak savings though some lights are likely to be in use. 1997 savings assume a gradual build-up in which 15% of 1997 customers are enrolled.

Notes to Tables 1 and 2
Continued

5. Time of use rates were considered as an option for residential customers. Maximum saturation of 5% was assumed by 2009. The program was dropped because of its "small impact". (Ref. p. 1B.6.4-10). The 2002 figure shown is OUC's 2009 figure scaled back for a smaller number of residential customers, but assuming that 5% can be reached in 11 years. The 1997 figure is a linear interpolation. Winter peak, summer peak and annual GWh are taken as ratios from data given on p. 1B.6.4-13

Commercial Lighting

OUC has a commercial lighting program with existing FEECA conservation programs, though no savings are listed before 1991. (Ref. p. 1B.6.1-20) Thisprogram is planned, by 1999, to reach 330 customers. Savings (6.1 MW) are already deducted in the demand forecasts.

An expanded program, with customer incentives, is examined, foud to be highly cost-effective, and, apparently is to be implemented. (Ref. p. 1B.11.6-1). This would add, by 2009, an additional saving of 24 MW (Winter peak), 9 MW (summer peak) and 182GWh annually. (Ref. p. 1B.6.4-13)

For 1997, OUC's figures are adopted - 7 MW (winter peak) (Ref. p. 1B.6.4-15) Summer peak and GWh savings are taken in proportion to the 2009 figures. (2.6 MW and 53 GWh, resp.)

For 2002, an accelaeration of [illegible] years is proposed. That would bring 2007 savings into 2002, or 21.2 MW (winter peak). Summer Peak and GWh savings are again taken in theproportions shown for the year 2009. (summer peak= [illegible] 8 MW, annual= 160 GWh)

These programs have already been screened for cost effectiveness and are highly so. (Ref. p. 1B.11.6-1)

Composite Page 7

Residential Efficient Lighting
Thisprogram offers utility incentives for residents to replace incandescent lamps with compact fluorescents, saving about 70% of thelighting energy for each bulb replaced. Compact fluorescents cost much more than ordinary bulbs but last much longer.

The OUC program estimated that but half the lighting energy was in bulbs which could be replaced, since fixtures are not now designed for compact fluorescents. If an average residential customer uses 1,000 kwh for lighting, replacing half of this use with bulbs which save about 70% would reduce lighting energy use 350 kwh per year per participating residence, not 175 used in the OUC calcultions. The cost of saved energy runs to -4¢ per kwh saved, depending on the number of hours a particular light is on.

OUC showed only winter peak savings and kwh savings. Some fraction of lights are also on during summer peak hours in residences (noon-9 p.m.) so that a small additional saving in 2002 is taken for the summer peak.

The OUC program which was calculated to be so highly cost-effective wouâd pay half the cost of compact fluorescents. This could be routinely distributed in all other residential programs which bring OUC personnel in contact with consumers, as well as in a variety of promotion programs.

Window Film for Commercial Buildings

OUC examines a window film program with incentives, and finds it cost-effective. (Ref. p. 1B.6.3-20). It is so highly cost-effective for the consumer that OUC decides not to give incentives but to encourage its adoption.

This, in principle, is a correct approach. Yet experience with utility programs elsewhere suggests that even measures with 1-year paybacks will be adopted voluntarily by only about 40% of customers over a 10-year period.

Since the program yields considerable savings (21 GWh by 1997, reference just given, and summer peak savings of 6.7 MW, as calculated from data on p. 1B.6.3-26), we recommend that OUC maintain this incentive program. We also project winter peak savings of 2 MW in 1997, from data on p. 1B.6.3-27, though none are shown in the first reference by OUC. We recommend that this program be continued until 80% saturation is achieved. The commercial building code will bring this measure to new buildings. OUC show market penetration of 20% in 1990. We estimate savings of 42 GWh in 2002, with 13.4 MW off summer peak demand and 4 MW off winter peak demand.

We recommend incentive programs to improve the efficiency of HVAC equipment. Some of these measures were screened for cost-effectiveness by OUC and its consultants and found not to pass the cost-benefit test.

In some cases, these findinings are inconsistent with the input data used in the screening.
First, we consider high-efficiancy heat pumps, typically used among generl service non-demand customers.

Table 1B.6.3-5 (p. 1B.6.3-25 ff.) gives an incremental cost of $2,500 for a high-efficiency commercial heat pump. Kwh savings are 15,200 per year, with 4 kw off diversified winter peak and 5.6 kw off diversified summer peak. An equipment life of 17 years is shown. At OUC's borrowing rate of 7%, this implies a cost of energy saved of 1.3¢ per kwh or at 16% for private cost of capital, 2.9¢ per kwh. Winter peak capacity is being "bought" for $625 per kw.

Since these units appear to be cost-effective against variable costs only, it is not clear why they did not give stronger results in the screening. OUC program costs are shown at $150 per participant, not enough to change the results.

We therefore recommend an incentive program for commercial efficient heat pumps. The numbers of commercial-industrial general service non-demand customers are 13,221 in 1990, and projected to be 16,248 and 18,305 in 1997 and 2002, respectively. There are, therefor major opportunities in new installations for these customers choosing this heating-cooling method, as well as replacements ofequipment at the end of its service life among existing customers. We project 500 installations, cumulated, by 1997 and 2,000 by 2002.

1997 savings are 7.6GWh, 2 MW winter peak and 2.8 MW summer peak

2002 savings are 30.4 GWh, 8 MW winter peak and 11.2 MW summer peak.

Commercial Heating, Ventilating and Air Conditioning

We recommend incentive programs to improve the efficiency of HVAC equipment. Some of these measures were screened for cost-effectiveness by OUC and its consultants and found not to pass the cost-benefit test.

In some cases, these findinings are inconsistent with the input data used in the screening.
First, we consider high-efficiency heat pumps, typically used among generl service non-demand customers.

Table 1B.6.3-5 (p. 1B.6.3-25 ff.) gives an incremental cost of $2,500 for a high-efficiency commercial heat pump. Kwh savings are 15,200 per year, with 4 kw off diversified winter peak and 5.6 kw off diversified summer peak. An equipment life of 17 years is shown. At OUC's borrowing rate of 7%, this implies a cost of energy saved of 1.3¢ per kwh or at 16% for private cost of capital, 2.9¢ per kwh. Winter peak capacity is being "bought" for $625 per kw.

Since these units appear to be cost-effective against variable costs only, it is not clear why they did not give stronger results in the screening. OUC program costs are shown at $150 per participant, not enough to change the results.

We therefore recommend an incentive program for commercial efficient heat pumps. The numbers of commercial-industrial general service non-demand customers are 13,221 in 1990, and projected to be 16,248 and 18,505 in 1997 and 2002, respectively. There are, therefor major opportunities in new installations for these customers choosing this heating-cooling method, as well as replacements ofequipment at the end of its service life among existing customers. We project 500 installations, cumulated, by 1997 and 2,000 by 2002.

1997 savings are 7.6GWh, 2 MW winter peak and 2.8 MW summer peak

2002 savings are 30.4 GWh, 8 MW winter peak and 11.2 MW summer peak.

Composite Page 10

Commercial Air Conditioning Units

Major electricity and dollar savings are available b y installing high-efficiency Air conditioning in new construction or in replacing units that arewearing out. Savings are available by going to efficiency levels well beyond those now being considered for strengthening the commercial building code.

Incentives will be necessary to realize these savings. Surveys done by the Florida Solar Energy Center in the process of examining code revisions indicate that existing practices just barely comply. Developers and builders are anxious to hold down first costs, and still do not consider life cycle savings in commercial construction

Information from 2 equipment suppliers was used to evaluate dollar and energy savings for package units and chillers, both air cooled and water cooled.

Energy reductions for delivering cooling run from 20 to 27%, with costs of saved energy ranging from .6¢ to 3.5¢per Khw. Costs of summer peak capacity avoided range from $117 to $400 per kw. This is apparently more efficient equipment than was examined in OUC's screening. The proposed new commercial building code will generally bring in about half the potential savings.

OUC has theopportunity, through incentives, to bring new and replacemet equipment to high levels of efficiency, with major savings in dollars and electricity.

Commercial air conditioning takes about 45% of commercial electricity. Since OUC's general service customers (demand and non-demand) are over 80% commercial (by kwh usage), this implies 650-700 GWh of electricity for commercial air onditionin in 1990, 1100-1200 in 1997, and 1400-1500 in 2002. A large and rising share of <u>all</u> electricity demand in the OUC service territory is for commercial air conditioning - 20-25%. By 2002, half of this will be new construcction.

Incentives of $75-150 per kw saved, depending on the size of the units,with a target penetration of 15% (via new and replacement equipment) are proposed. This would reduce electricity use by 45 Gwh and avoid 22.5 MW of summer capacity.

Summary of Commercial HVAC program savings

	Winter Peak	Summer Peak	GWh
1997 - Heat pump only	2	2.8	7.6
2002 - Heat pump program	8	11.2	30.4
Cooling Equipment	-	22.5	45
	8	33.7	75.4

Composite Page 11

Builder Conservation Incentives - Residential

Orlando Utilities projections show 37,600 additional residential customers by 2002 (a 37% increase) and 75,000 by 2020. Since sime existing residences will be replaced, builders will construct perhaps 40,000 new homes and apartment units in the Orlando Utilities Commission service area.by 1997 and perhaps 80,000 by 2020.

Single family homes in the 1,500-1,600 square foot range built to 1986 code specifications in Central Florida would use about 500-1000 kwh for heat and 3500-4500 kwh for cooling. This is a dramatic reduction from figures in the early 1970's. Similar all-electric homes would then have used 2000-5000 kwh for heat (depemding on whether or not a heat pump was used) and around 8,000 kwh for cooling.

The Florida Solar Energy Center has designed and modelled the energy performance of an energy conserving home. By adding a radiant barrier in the attic, additional wall insulation, moving window areas to the north and south and away from the east and west sides, + reducing total window area, heating and cooling loads are further reduced dramatically. Such a house, which would cost about $1,000 more to build, would use but 200 kwh for heat and 2100 kwh for cooling. Annual energy savings, $165 initially, escalating, would cover the additional mortage payments ($100) and leave the occupant with rising annual savings over the years. Such houses "save" energy, at 3.5-4¢ per kwh, a much better bargain than producing it at higher costs.

Builders and developers have little incentive to install these features, for they do not pay the annual energy costs. Moreover, the difference in energy efficiency may be lost in the buyer's considerations. Yet the cumulated differences to Orlando are enormous. Building new homes and apartments to these standards which go beyond the present code, would remove nearly 1/6 of anticipated growth in residential electric demand. Peak demands would be reduced by about 40 50 MW, winter and summer.

Builder incentives of $400 per single family residence and $200 per apartment unit are propoesed. A cumulated response rate of 4% by 1997 and 15% by 2002 would produce the capacity and kwh savings indicated in Tables 1 and 2 - 1 and 6 peak megawatts for 1997 and 2002, respectively, and Gwh savings of 1.3 and 10.

Composite Page 12

Customer Cogeneration

OUC screened its customers for those who use process heat and electricity. This screening revealed 44 potential cogenerators. Of these, 12 appeared to be able to save money through cogeneration, and to displace 29 MW of capacity. Another 9 were sufficiently close to the cut-off point to warrant further investigation, bringing the total to 50 MW. (Ref. p. 1B.8.3-13) These were OUC estimates only, based on electricity usage, hot water or process heat usage, and estimated capital and operating costs of cogenerating equipment.

This is a customer class which is expected to grow rapidly - by a factor of1.75 between 1990 and 2002 (Ref. p. 1B.A.12-15) Applying this factor to the 29 MW above gives an estimate of a 50MW potential by 2002.

This does not consider customers who might also use gas-driven chillers for air conditioning and cogenerate.

Some other Florida utilities are vigorously pursuing cogeneration.

We propose that OUC pursue and encourage the development of 40% of its estimated potential by 2002.

This gives 20 MW, and, at a 70% capacity factor, 122 GWh.

Summary of Intervenors' Proposed Alternative

We have presented 11 conservation - load management - cogeneration proposals which, taken together, would defer Stanton 2 for five years, looking for the moment at the OUC service area.

3 of these programs are already in place or are scheduled to be implemented . (Curtailable rates, Commercial Lighting, Residential heat pumps)

2 more were examined by OUC, found to be cost effective, but not scheduled for implementation. (Residential Lighting and commercial window films)

1 more was developed by OUC but not adopted because of its small impact (Residential time-of use rates)

1 more - our customer cogeneration proposal - was drawn from OUC data and represents a fraction of the potential generation as projected, for customers who could save money by cogenerating.

Cost-effectiveness of 6 of these 7 programs is demonstrated in the OUC application. Cost-effectiveness of time-of-use rates eas not given, but failure to be cost-effective was not the reason given for dropping this element.

Load control measures, using OUC data, defer capacity at costs of $45-50 per year, cumulating OUC's equipment and administration costs and amortizing them, along with annual costs. Our propsed expanded and accelerated program would raise costs but increase savings, and change these figures very little.

These would have shown up as cost-effective if enough conservation - load management had been done in OUC's modelling actually to defer generating capacity.

Our commercial heat-pum proposal in the commercial HVAC section, is highly cost-effective using OUC program input data. It is not clear why it did not appear to be so in OUC's screening. Any measure which saves electricity at 1.3¢ per kwh must continue to be cost effective even when substantial program costs are added.

Basically, we propose only two new programs which cannot be shown to be cost effective from OUC's own data. One is the builder incentive program and the other is commercial high-efficiency air conditioning. Cost of saved energy, given in the narrative, range from .6¢ to 4c per kwh. All of these are sufficiently cheaper than electricity from Stanton 2 to permit program costs to be covered.

Kissimmee

KUA, among all of the proposed Stanton 2 participants, has the largest difference between generating capacity owned and projected future demand. Residential and General Service customer growth has been rapid, and is expected to continue to be the highest of all the participants.

Clearly, even with an agressive conservation program, Kissimmee will need additional generating capacity. We will recommend enhanced conservation efforts, but we first comment on the economics of KUA's participation in Stanton 2.

In examining supply alternatives, a 60 MW combined cycle unit showed the lowest present worth of revenue requirements. The consultant's opinion that Stanton 2 represented the lowest-cost supply expansion represented on an hypothetical case not actually available to KUA. The consultant may be right, but cannot have reached his conclusion on the basis of information in the Application. Should 16.9 MW (gross) of Stanton 2 be taken rather than a 60 MW combined cycle unit, this would be a lower-cost alternative if and only if the remaining supply (60 MW less Stanton 2) were available at costs sufficiently lower than electricity from Florida Power Corp so asto give an average cheaper than the combined cycle unit. One would expect some discussion of possible sources and their costs, but none is provided.

Furthermore, at lower gas and oil prices than those used in the economic analyses, the combined cycle unit might be the least cost supply option. Florida Power Corp has recently lowered its estimates of future gas prices, bringing them to levels well below those used in the KUA economic analysis. These prices would significantly decrease any hypothetical cost advantage of Stanton 2, and, possibly, through effects on prices of electricity available from FPC to Kissimmee, eliminate that advantage.

Conservation Programs.
KUA projects conservation and load management savings which are relatively ambitious compared to neighboring utilities. (reductions exceeding 7 % in 1997 and 8% in 2002 from otherwise forecasted demand). An additional 5% or so would be required to displace electricity from Stanton 2.

Load Management
We observe that load management targets already given are unlikely to be realized in the absence of customer incentives. We recommend that incentives similar to those proposed by OUC be adopted, and that the program be accelerated with targets of 7 MW in 1997 and 14 MW in 2002.

Kissimmee (Continued)

We observe that water heater conversion program targets are unlikely to be met without customer incentives.

We propose that commercial lighting be included as a new program with 1997 target reductions of 1.3MW and 2002 reductions of 6.5 MW. These figures are derived by scaling KUA's system size to Orlando's proposed program.

Most importantly, since the stock of residences will be doubled in 2 decades, and the stock of commercial buildings nearly so, we recommend builder incentive programs to encourage energy efficiency in construction and inital installation of electricity-using equipment. Given the strained supply situation in Kissimmee, the Utility should also consider hook-up fees scaled according to the energy efficiency of new buildings. Efficient buildings would receive incentive payments, while those barely meeting or failing to meet building energy code requirements would be charged per kw and per kwh the full amount that KUA expects to pay suppliers.

About a quater of FMPA's purchase of Stanton 2 - 21.5 MW, is to supply electricity to 6 cities. Bushnell, Clewiston, Green Cove Springs, Jacksonville Beach, Leesburg and Ocala are the participants.

The economic analysis for this Project is inconclusive. The PresentWorth Revenue Requirement calculation shows a saving of only .03% over the next best alternatives, with negative benefits for many years. When lower gas and oil prices are examinined in one sensitivity analysis comparison, the present worth of benefits turns negative.

Clearly Stanton 2 would not be built if all participants had so marginal a case. We therefore do not discuss this group further, except to fecommend that conservation programs be expanded, perhaps with FMPA expanding its role to provide assistance for the smaller cities. Ocala, the largest participant, has a load management program. It has apparently been expanded beyond the figures shown in the Application, since the 1991 Ten-Year Plan, FEPCG, shows winter and summer MW savings in the year 2000 of 8 and 6 MW, respectively, compared to 5.8 and 3.8 in the Application.

FMPA Participants

Of the six cities listed as participants, two have miniscule benefits aseconomic analysis is applied, and these diminish as lower gas and oil prices are examined. These two cities, Starke and Key West, are not examined further, though they, as in all cases, can benefit from expanded conservation efforts.

During the period 1997-2002, when we propose that Stanton 2 be deferred, peak demand is expected to increase as follows in the four remaining cities:

Fort Pierce	7 MW
Vero Beach	18 MW
Homestead	5 MW
Lake Worth	7 MW

Conservation-load management substitutes for this capacity and associated energy must be found to leave these cities no worse off than they would have been with Stanton 2 during the period in which we seek to defer it. Moreover, costs of the conservation-load management programs must be no more than capacity and energy from Stanton 2.

We propose load management programs as follows. They are less costly than Stanton 2 capacity, but quite apart from that, they have merit in their own right, as all larger Florida utilities are coming to realize.

	Load Management Targets (MW)	
	1997	2002
Fort Pierce	1.1	5.0
Vero Beach	1.7	7.5
Homestead	.6	2.6
Lake Worth	.8	3.6

These targets are 1% and 4%, respectively, for the two years considered, of system peaks.

We recommend commercial lighting programs, which are among the most cost-effective af all utility programs in Florida and elsewhere. All but Homestead have Commercial-Industrial Audit Programs. This proposal would add financial incentives for commercial lighting efficiency gains.

	CommercialLighting Targets (MW saved - peak)	
	1997	2002
Fort Pierce	1.1	2.5
Vero Beach	1.7	3.8
Homestead	.6	1.3
Lake Worth	.8	1.8

These two programs replace capacity from Stanton 2 for Fort Pierce and, with a reserve margin applied, come very close for Homestead and Lake Worth. Energy saves is expensive peak energy, though detailed economic analysis would needto be done to compare energy saving with energy from Stanton 2.

All four cities should have programs, justified on their own merits, to reduce energy consumption in new residential and commercial construction. Incentives proposed for Orlando are equally applicable here.

Vero Beach would need 3.7 MW of savings from such programs or other of its choosing to offset the delay in electricity from Stanton 2, once reserve margins are applied. Homestead and Lake Worth would need very small amounts.

Opposite Page 19

:47

#0688

EMBEDDED COST BENEFIT ANALYSIS TO PARTICIPATING CUSTOMERS
PROGRAM: DLC-FPC COST

PSC FORM CE 3.6
16-Jun-91

YEAR	(1) PARTICIPATING CUSTOMER EMBEDDED SAVINGS IN BILLS $(000)	(2) MINUS PARTICIPATING CUSTOMER EQUIPMENT COSTS $(000)	(3) MINUS PARTICIPATING CUSTOMER O & M COSTS $(000)	(4) PARTICIPATING CUSTOMER TAX CREDIT $(000)	(5) PARTICIPATING CUSTOMERS SAVINGS $(000)	(6) UTILITY REBATE/ INCENTIVE $(000)	(7) PARTICIPATING CUSTOMERS SAVINGS WITH UTILITY/REBATE INCENTIVE $(000)
1992	15	0	(213)	0	228	0	228
1993	57	0	(758)	0	815	0	815
1994	84	0	(1,103)	0	1,188	0	1,188
1995	121	0	(1,545)	0	1,666	0	1,666
1996	172	0	(2,131)	0	2,303	0	2,303
1997	220	0	(2,669)	0	2,890	0	2,890
1998	226	0	(2,669)	0	2,896	0	2,896
1999	232	0	(2,669)	0	2,901	0	2,901
2000	238	0	(2,669)	0	2,907	0	2,907
2001	244	0	(2,669)	0	2,914	0	2,914
2002	250	0	(2,669)	0	2,920	0	2,920
2003	257	0	(2,669)	0	2,926	0	2,926
2004	264	0	(2,669)	0	2,933	0	2,933
2005	270	0	(2,669)	0	2,940	0	2,940
2006	277	0	(2,669)	0	2,947	0	2,947
2007	285	0	(2,669)	0	2,954	0	2,954
2008	292	0	(2,669)	0	2,961	0	2,961
2009	300	0	(2,669)	0	2,969	0	2,969
2010	307	0	(2,669)	0	2,977	0	2,977
2011	315	0	(2,669)	0	2,985	0	2,985
2012	323	0	(2,669)	0	2,993	0	2,993
2013	332	0	(2,669)	0	3,001	0	3,001
2014	340	0	(2,669)	0	3,010	0	3,010
2015	349	0	(2,669)	0	3,019	0	3,019
2016	358	0	(2,669)	0	3,028	0	3,028
	--------	--------	--------	--------	--------	--------	--------
NOMINAL	6,131	0	(59,139)	0	65,270	0	65,270
NPV:	2,533	0	(26,269)	0	28,802	0	28,802

#0688

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 910382-EM EXHIBIT NO. 47
COMPANY/ WITNESS: Rollins
DATE: 6/19/91

FLORIDA SOCIETAL BENEFIT   PSC FORM 3.5
PROGRAM: DLC-FPC COST   16-Jun-91

	----COMPANY EXPENDITURES--			---INDIVIDUAL CUSTOMER AND OTHER COST----------				-------TOTALS-------		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	NON-RE CURRING COST $(000)	RE- CURRING COST $(000)	TOTAL COMPANY COST $(000)	PARTICIPATING CUSTOMERS EQUIPMENT COST $(000)	PARTICIPATING CUSTOMERS O & M COST $(000)	OTHER COSTS MINUS OTHER BENEFITS $(000)	TOTAL PARTICIPATING CUSTOMERS AND OTHER COSTS $(000)	TOTAL PROGRAM COST $(000)	TOTAL AVOIDED COSTS $(000)	NET SAVINGS TO FLORIDA $(000)
1992	268	237	504	0	(213)	0	(213)	292	7	(285)
1993	719	847	1,566	0	(758)	0	(758)	807	25	(782)
1994	476	1238	1,714	0	(1,103)	0	(1,103)	611	39	(572)
1995	638	1742	2,380	0	(1,545)	0	(1,545)	835	60	(776)
1996	889	2415	3,304	0	(2,131)	0	(2,131)	1,173	100	(1,073)
1997	854	3040	3,894	0	(2,669)	0	(2,669)	1,225	(817)	(2,042)
1998	0	3056	3,056	0	(2,669)	0	(2,669)	386	(1,126)	(1,512)
1999	0	3071	3,071	0	(2,669)	0	(2,669)	401	(2,782)	(3,184)
2000	0	3086	3,086	0	(2,669)	0	(2,669)	417	(5,005)	(5,422)
2001	0	3102	3,102	0	(2,669)	0	(2,669)	432	(5,015)	(5,447)
2002	0	3117	3,117	0	(2,669)	0	(2,669)	448	(6,747)	(7,195)
2003	0	3133	3,133	0	(2,669)	0	(2,669)	463	(8,784)	(9,247)
2004	0	3148	3,148	0	(2,669)	0	(2,669)	479	(9,540)	(10,019)
2005	0	3164	3,164	0	(2,669)	0	(2,669)	495	(11,470)	(11,964)
2006	0	3180	3,180	0	(2,669)	0	(2,669)	510	(15,133)	(15,644)
2007	0	3196	3,196	0	(2,669)	0	(2,669)	526	(15,756)	(16,283)
2008	0	3212	3,212	0	(2,669)	0	(2,669)	542	(20,569)	(21,112)
2009	0	3228	3,228	0	(2,669)	0	(2,669)	558	(26,704)	(27,262)
2010	0	3244	3,244	0	(2,669)	0	(2,669)	575	(35,961)	(36,536)
2011	0	3260	3,260	0	(2,669)	0	(2,669)	591	(43,968)	(44,559)
2012	0	3277	3,277	0	(2,669)	0	(2,669)	607	(54,116)	(54,723)
2013	0	3293	3,293	0	(2,669)	0	(2,669)	623	(57,790)	(58,414)
2014	0	3309	3,309	0	(2,669)	0	(2,669)	640	(74,159)	(74,799)
2015	0	3326	3,326	0	(2,669)	0	(2,669)	656	(96,172)	(96,799)
2016	0	3343	3,343	0	(2,669)	0	(2,669)	673	(106,479)	(107,152)
	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
NOMINAL	3,844	70,262	74,106	0	(59,139)	0	(59,139)	14,967	(597,825)	(612,792)
NPV:	3,161	30,776	33,937	0	(26,269)	0	(26,269)	7,668	(160,022)	(167,690)

ALL CUSTOMER COST BENEFIT ANALYSIS — PSC FORM 3.4

PROGRAM: DLC-FPC COST — 16-Jun-91

YEAR	(1) TOTAL AVOIDED KW & KWH COSTS $(000)	(2) COMPANYS TOTAL COST $(000)	(3) TOTAL CONSER PROGRAM SAVINGS $(000)	(4) PARTICIPATING CUST SAVINGS IN BILL/TOTAL EMBEDDED COST $(000)	(5) ALL CUSTOMER BENEFIT/ NO GROWTH UTILITY $(000)	(6) PARTICIPATING CUST SAVINGS IN BILL/FUEL COST ONLY $(000)	(7) ALL CUST BENEFIT/ GROWTH UTILITY $(000)
1992	7	504	(497)	15	(513)	5	(503)
1993	25	1,566	(1,541)	57	(1,597)	19	(1,560)
1994	39	1,714	(1,676)	84	(1,760)	28	(1,704)
1995	60	2,380	(2,320)	121	(2,441)	41	(2,361)
1996	100	3,304	(3,204)	172	(3,376)	58	(3,262)
1997	(817)	3,894	(4,711)	220	(4,932)	74	(4,786)
1998	(1,126)	3,056	(4,182)	226	(4,408)	76	(4,258)
1999	(2,782)	3,071	(5,853)	232	(6,085)	78	(5,931)
2000	(5,005)	3,086	(8,091)	238	(8,329)	80	(8,171)
2001	(5,015)	3,102	(8,117)	244	(8,361)	82	(8,199)
2002	(6,747)	3,117	(9,864)	250	(10,115)	84	(9,949)
2003	(8,784)	3,133	(11,917)	257	(12,174)	87	(12,003)
2004	(9,540)	3,148	(12,689)	264	(12,952)	89	(12,778)
2005	(11,470)	3,164	(14,634)	270	(14,904)	91	(14,725)
2006	(15,133)	3,180	(18,313)	277	(18,591)	93	(18,407)
2007	(15,756)	3,196	(18,952)	285	(19,237)	96	(19,048)
2008	(20,569)	3,212	(23,781)	292	(24,073)	98	(23,879)
2009	(26,704)	3,228	(29,931)	300	(30,231)	101	(30,032)
2010	(35,961)	3,244	(39,205)	307	(39,513)	104	(39,309)
2011	(43,969)	3,260	(47,228)	315	(47,544)	106	(47,335)
2012	(54,116)	3,277	(57,393)	323	(57,716)	109	(57,502)
2013	(57,790)	3,293	(61,083)	332	(61,415)	112	(61,195)
2014	(74,159)	3,309	(77,468)	340	(77,809)	115	(77,583)
2015	(96,132)	3,326	(99,458)	349	(99,807)	118	(99,576)
2016	(106,479)	3,343	(109,822)	358	(110,180)	121	(109,942)
NOMINAL	(597,825)	74,106	(671,931)	6,131	(678,062)	2,065	(673,996)
NPV:	(160,022)	33,937	(193,959)	2,533	(196,493)	853	(194,813)

KWH FUEL COSTS SAVINGS DUE TO CONSERVATION PROGRAM PSC FORM CE 3.3
PROGRAM: DLC-FPC COST 16-Jun-91

YEAR	(1) KWH SAVINGS (000)	(2) AVOIDED MARGINAL FUEL $(000)	(3) GAIN IN OFF-SYS SALES $(000)	(4) TOTAL FUEL COST SAVINGS $(000)
1992	230	7	0	7
1993	820	25	0	25
1994	1,193	39	0	39
1995	1,670	60	0	60
1996	2,305	100	0	100
1997	2,887	111	0	111
1998	2,887	156	0	156
1999	2,887	184	0	184
2000	2,887	219	0	219
2001	2,887	228	0	228
2002	2,887	258	0	258
2003	2,887	293	0	293
2004	2,887	312	0	312
2005	2,867	347	0	347
2006	2,887	403	0	403
2007	2,887	423	0	423
2008	2,887	494	0	494
2009	2,887	584	0	584
2010	2,867	711	0	711
2011	2,887	822	0	822
2012	2,887	962	0	962
2013	2,887	1,023	0	1,023
2014	2,887	1,240	0	1,240
2015	2,587	1,515	0	1,515
2016	2,887	1,661	0	1,661
	--------	--------	--------	--------
NOMINAL	63,953	12,177	0	12,177
NPV:		3,796	0	3,796

#0##

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-FPC COST

FSC FOR CE 3.2.B
16-Jun-91

YEAR	(10) AVOIDED TRANS INVEST $(000)	(11) AVOIDED TRANS VOD FACT	(12) AVOIDED TRNS FIXED COST/YR $(000)	(13) AVOIDED TRANS FIXED O & M $(000)	(14) AVOIDED DIST INVEST $(000)	(15) AVOIDED DIST VOD FACT	(16) AVOIDED DIST FIXED COST/YR $(000)	(17) AVOIDED DIST FIXED O & M $(000)	(18) AVOIDED TRN&DST COST $(000)	(19) TOTAL AVOIDED KW COST $(000)
1992	0	0.0000	0	0	0	0.0000	0	0	0	0
1993	0	0.0000	0	0	0	0.0000	0	0	0	0
1994	0	0.0000	0	0	0	0.0000	0	0	0	0
1995	0	0.0000	0	0	0	0.0000	0	0	0	0
1996	1,133	0.0000	0	0	0	0.0000	0	0	0	0
1997	1,133	0.0446	51	30	0	0.0446	0	0	80	(928)
1998	1,133	0.0466	53	31	0	0.0466	0	0	84	(1,282)
1999	1,133	0.0487	55	33	0	0.0487	0	0	88	(2,966)
2000	1,133	0.0509	58	34	0	0.0509	0	0	92	(5,224)
2001	1,133	0.0532	60	36	0	0.0532	0	0	96	(5,243)
2002	1,133	0.0556	63	37	0	0.0556	0	0	100	(7,005)
2003	1,133	0.0581	66	39	0	0.0581	0	0	105	(9,077)
2004	1,133	0.0607	69	41	0	0.0607	0	0	110	(9,853)
2005	1,133	0.0634	72	43	0	0.0634	0	0	115	(11,817)
2006	1,133	0.0663	75	45	0	0.0663	0	0	120	(15,537)
2007	1,133	0.0693	78	47	0	0.0693	0	0	126	(16,179)
2008	1,133	0.0724	82	49	0	0.0724	0	0	131	(21,064)
2009	1,133	0.0757	86	52	0	0.0757	0	0	137	(27,287)
2010	1,133	0.0791	90	54	0	0.0791	0	0	144	(36,672)
2011	1,133	0.0826	94	57	0	0.0826	0	0	150	(44,791)
2012	1,133	0.0863	98	59	0	0.0863	0	0	157	(55,078)
2013	1,133	0.0902	102	62	0	0.0902	0	0	164	(58,813)
2014	1,133	0.0943	107	65	0	0.0943	0	0	172	(75,799)
2015	1,133	0.0985	112	68	0	0.0985	0	0	180	(97,648)
2016	1,133	0.1030	117	72	0	0.1030	0	0	188	(106,140)
NOMINAL			1,585	955			0	0	2,540	(610,002)
NPV:			579	347			0	0	926	(163,819)

#0##

a0eae

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-FPC COST

PSC FORM CE 2.2.A
16-Jun-91

YEAR	(1) AVOIDED GEN UNIT INVEST $(000)	(2) AVOIDED GEN UNIT VOD FACT	(3) AVOIDED GEN FIXED COST/YR $(000)	(4) ANNUAL KWH GEN OF AVOIDED UNIT GEN (000)	(5) AVOIDED FUEL COST $(000)	(6a) AVOIDED UNIT FIXED O&M COST $(000)	(6b) AVOIDED UNIT VARIABLE O&M COST $(000)	(7) MINUS THE COST OF ENERGY NOT DISPLACED $(000)	(8) MINUS LOSS IN OFF-SYS SALES $(000)	(9) AVOIDED NET GEN COST $(000)
1992	4,038	0.0000	0	0	0	0	0	0	0	0
1993	11,293	0.0000	0	0	0	0	0	0	0	0
1994	30,838	0.0000	0	0	0	0	0	0	0	0
1995	46,497	0.0000	0	0	0	0	0	0	0	0
1996	57,338	0.0000	0	0	0	0	0	0	0	0
1997	57,338	0.0446	2,558	247,434	7,262	1,261	66	12,155	0	(1,008)
1998	57,338	0.0466	2,673	247,434	7,712	1,321	69	13,141	0	(1,366)
1999	57,338	0.0487	2,793	247,434	8,190	1,384	72	15,494	0	(3,054)
2000	57,338	0.0509	2,919	247,434	8,699	1,450	76	18,459	0	(5,316)
2001	57,338	0.0532	3,050	247,434	9,238	1,519	79	19,226	0	(5,339)
2002	57,338	0.0556	3,188	247,434	9,811	1,591	83	21,779	0	(7,106)
2003	57,338	0.0581	3,331	247,434	10,420	1,666	87	24,687	0	(9,182)
2004	57,338	0.0607	3,481	247,434	11,067	1,746	91	26,347	0	(9,963)
2005	57,338	0.0634	3,638	247,434	11,753	1,828	95	29,246	0	(11,931)
2006	57,338	0.0663	3,801	247,434	12,482	1,915	100	33,956	0	(15,657)
2007	57,338	0.0693	3,972	247,434	13,257	2,006	105	35,645	0	(16,305)
2008	57,338	0.0724	4,151	247,434	14,079	2,102	110	41,637	0	(21,195)
2009	57,338	0.0757	4,338	247,434	14,953	2,201	115	49,032	0	(27,425)
2010	57,338	0.0791	4,533	247,434	15,880	2,306	120	59,656	0	(36,816)
2011	57,338	0.0826	4,737	247,434	16,866	2,415	126	69,085	0	(44,941)
2012	57,338	0.0863	4,950	247,434	17,912	2,530	132	80,760	0	(55,236)
2013	57,338	0.0902	5,173	247,434	19,023	2,650	138	85,962	0	(58,977)
2014	57,338	0.0943	5,406	247,434	20,203	2,776	145	104,101	0	(75,571)
2015	57,338	0.0985	5,649	247,434	21,457	2,908	152	127,993	0	(97,827)
2016	57,338	0.1030	5,903	247,434	22,788	3,046	159	140,225	0	(108,328)
NOMINAL			80,247	4,948,676	273,052	40,623	2,121	1,008,564	0	(612,542)
NPV			29,297		96,161	14,752	770	305,724	0	(164,744)

a0eae

2017	22,935	1,728	0	0	0	1,728	1,638	0	3,366	0.0587	6,169	0.1076
2018	21,297	1,612	0	0	0	1,612	1,638	0	3,251	0.0567	6,447	0.1124
2019	19,659	1,497	0	0	0	1,497	1,638	0	3,135	0.0547	6,737	0.1175
2020	18,020	1,382	0	0	0	1,382	1,638	0	3,020	0.0527	7,040	0.1228
2021	16,382	1,267	0	0	0	1,267	1,638	0	2,905	0.0507	7,357	0.1283
2022	14,744	1,152	0	0	0	1,152	1,638	0	2,790	0.0487	7,688	0.1341
2023	13,106	1,037	0	0	0	1,037	1,638	0	2,675	0.0466	8,034	0.1401
2024	11.468	921	0	0	0	921	1,638	0	2,560	0.0446	8,395	0.1464
2025	9,829	806	0	0	0	806	1,638	0	2,444	0.0426	8,773	0.1530
2026	8,191	691	0	0	0	691	1,638	0	2,329	0.0406	9,168	0.1599
2027	6,553	576	0	0	0	576	1,638	0	2,214	0.0386	9,580	0.1671
2028	4,915	461	0	0	0	461	1,638	0	2,099	0.0366	10,011	0.1746
2029	3,276	346	0	0	0	346	1,638	0	1,984	0.0346	10,462	0.1825
2030	1,638	230	0	0	0	230	1,638	0	1,869	0.0326	10,933	0.1907
2031	0	115	0	0	0	115	1,638	0	1,753	0.0306	11,425	0.1993

Nominal:	129,893		208,464
NPV:	43,694		43,694
K Factor:	1.0703		

#9838

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-FPC COST

PSC FORM CE 3.1.B
16-Jun-91

VI. FINANCIAL DATA

(1) GENERATION				(2) TRANSMISSION AND DISTRIBUTION			
(1A) DEBT.........%	100	COST	7.03 %	(2A) DEBT.............%	100	COST	7.03 %
(1B) PREFERRED... %	0	COST	0 %	(2B) PREFERRED........%	0	COST	0 %
(1C) EQUITY.......%	0	COST	0 %	(2C) EQUITY...........%	0	COST	0 %
(1D) EFFECTIVE TAX RATE.............			0 %	(2D) EFFECTIVE TAX RATE.......................			0 %
(1E) GENERATOR TAX LIFE.............			35 YEARS	(2E) TRANSMISSION TAX LIFE....................			35 YEARS
(1F) INSURANCE AND OTHER TAXES.......			0 %	(2F) INSURANCE AND OTHER TAXES................			0 %

(3) DISCOUNT RATE			
(3A) UTILITY.........................	7.03 %	(3C) K Factor for Avoided Gen Unit [Calc.].....	1.0703
(3B) CUSTOMER........................	10.2 %	(3D) K Factor for Avoided T & D [Calc.]........	1.0703

VII. DERIVATION OF CAPITAL CARRYING CHARGES FOR AVOIDED GENERATION

YEAR	(1) AVOIDED ELECTRIC PLANT IN SERVICE $(000)	(2) DEBT $(000)	(3) PREFERRED $(000)	(4) EQUITY $(000)	(5) TAX $(000)	(6) TOTAL DEBT PREFERRED EQUITY & TAX $(000)	(7) DEPREC $(000)	(8) INSURANCE & OTHER TAXES $(000)	(9) TOTAL ANNUAL FIXED COST $(000)	(10) AVOIDED GEN UNIT CCR	(11) VALUE OF DEFERRAL $(000)	VALUE OF DEFERRAL FACTOR
1992	4,038	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1993	11,293	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1994	30,838	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1995	46,497	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1996	57,338	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1997	55,699	4,031	0	0	0	4,031	1,638	0	5,669	0.0989	2,558	0.0446
1998	54,061	3,916	0	0	0	3,916	1,638	0	5,554	0.0969	2,673	0.0466
1999	52,423	3,801	0	0	0	3,801	1,638	0	5,439	0.0949	2,793	0.0487
2000	50,785	3,685	0	0	0	3,685	1,638	0	5,324	0.0928	2,919	0.0509
2001	49,147	3,570	0	0	0	3,570	1,638	0	5,208	0.0908	3,050	0.0532
2002	47,508	3,455	0	0	0	3,455	1,638	0	5,093	0.0888	3,188	0.0556
2003	45,870	3,340	0	0	0	3,340	1,638	0	4,978	0.0868	3,331	0.0581
2004	44,232	3,225	0	0	0	3,225	1,638	0	4,863	0.0848	3,481	0.0607
2005	42,594	3,110	0	0	0	3,110	1,638	0	4,748	0.0828	3,638	0.0634
2006	40,955	2,994	0	0	0	2,994	1,638	0	4,633	0.0808	3,801	0.0663
2007	39,317	2,879	0	0	0	2,879	1,638	0	4,517	0.0788	3,972	0.0693
2008	37,679	2,764	0	0	0	2,764	1,638	0	4,402	0.0768	4,151	0.0724
2009	36,041	2,649	0	0	0	2,649	1,638	0	4,287	0.0748	4,338	0.0757
2010	34,403	2,534	0	0	0	2,534	1,638	0	4,172	0.0728	4,533	0.0791
2011	32,764	2,419	0	0	0	2,419	1,638	0	4,057	0.0708	4,737	0.0826
2012	31,126	2,303	0	0	0	2,303	1,638	0	3,942	0.0687	4,950	0.0863
2013	29,488	2,188	0	0	0	2,188	1,638	0	3,826	0.0667	5,173	0.0902
2014	27,850	2,073	0	0	0	2,073	1,638	0	3,711	0.0647	5,406	0.0943
2015	26,211	1,958	0	0	0	1,958	1,638	0	3,596	0.0627	5,649	0.0985
2016	24,573	1,843	0	0	0	1,843	1,638	0	3,481	0.0607	5,903	0.1030

@@@@

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-FPC COST

PSC FORM CE 3.1.A
PAGE 2 OF 2
16-Jun-91

V. YEARLY INPUT DATA

YEAR	(1) CUMULATIVE PARTICIPATING CUSTOMERS	(2) MARGINAL FUEL COST WITH AVOIDED GENERATING UNIT — UTILITY — ON-PEAK (C/KWH)	(3) UTILITY — OFF PEAK (C/KWH)	(4) STATE — ON PEAK (C/KWH)	(5) STATE — OFF PEAK (C/KWH)	(6) MARGINAL FUEL COST W/O AVOIDED GEN UNIT — UTILITY — ON-PEAK (C/KWH)	(7) UTILITY — OFF PEAK (C/KWH)	(8) STATE — ON PEAK (C/KWH)	(9) STATE — OFF PEAK (C/KWH)
1992	2,093	3.02	2.53	3.02	2.53	3.02	2.53	3.02	2.53
1993	7,455	3.02	2.57	3.02	2.57	3.02	2.57	3.02	2.57
1994	10,847	3.25	2.76	3.25	2.76	3.25	2.76	3.25	2.76
1995	15,185	3.58	3.12	3.58	3.12	3.58	3.02	3.58	3.02
1996	20,952	4.32	3.49	4.32	3.49	4.32	3.49	4.32	3.49
1997	26,243	3.85	3.03	3.85	3.03	4.99	3.88	4.99	3.88
1998	26,243	4.13	3.33	4.13	3.33	5.39	4.26	5.39	4.26
1999	26,243	4.59	3.61	4.59	3.61	6.37	4.81	6.37	4.81
2000	26,243	5.17	4.02	5.17	4.02	7.60	5.58	7.60	5.58
2001	26,243	6.26	4.44	6.26	4.44	7.90	6.06	7.90	6.06
2002	26,243	6.95	4.88	6.95	4.88	8.95	6.82	8.95	6.82
2003	26,243	7.81	5.28	7.81	5.28	10.16	7.58	10.16	7.58
2004	26,243	8.33	5.94	8.33	5.94	10.82	8.31	10.82	8.31
2005	26,243	9.25	6.48	9.25	6.48	12.01	9.24	12.01	9.24
2006	26,243	10.54	7.11	10.54	7.11	13.97	10.44	13.97	10.44
2007	26,243	11.68	7.82	11.68	7.82	14.66	11.03	14.66	11.03
2008	26,243	13.12	8.78	13.12	8.78	17.13	12.82	17.13	12.82
2009	26,243	10.54	9.36	10.54	9.36	20.23	14.38	20.23	14.38
2010	26,243	11.77	7.49	11.77	7.49	24.62	17.37	24.62	17.37
2011	26,243	13.85	8.24	13.85	8.24	28.49	20.41	28.49	20.41
2012	26,243	15.53	9.45	15.53	9.45	33.33	23.49	33.33	23.49
2013	26,243	17.77	10.47	17.77	10.47	35.43	25.62	35.43	25.62
2014	26,243	13.10	11.88	13.10	11.88	42.95	30.46	42.95	30.46
2015	26,243	15.67	9.18	15.67	9.18	52.49	41.57	52.49	41.57
2016	26,243	12.00	10.60	12.00	10.60	57.53	45.28	57.53	45.28

@@@@

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-FPC COST

VOD: 20 YR PBM: 35 YR GEN TAX LIFE

I. CONSERVATION PROGRAM OPERATIONAL AND COST DATA

(1) GEN REDUCTION PER CUSTOMER....................	1.60 KW and 110 KWH
(2) PEAK REDUCTION PER CUSTOMER....................	1.90 KW
(3) KWH REDUCTION PER CUSTOMER....................	104.00 KWH
(4) KWH REDUCTION THAT IS ON PEAK....................	100 %
(5) TOTAL PARTICIPATING CUSTOMERS....................	26,243

II. CONSERVATION PROGRAM COST DATA

(1) UTILITY NON RECURRING COST PER CUSTOMER....................	$128
(2) UTILITY NON-RECURRING COST ESCALATION RATE....................	4.8 %
(3) UTILITY RECURRING COST PER CUST PER YEAR....................	$113
(4) UTILITY RECURRING COST ESCALATION RATE....................	0.5 %
(5) UTILITY REBATE/FINANCIAL INCENTIVE............	$0
(6) CUSTOMER EQUIPMENT COST PER CUST............	$0
(7) CUSTOMER EQUIPMENT ESCALATION RATE............	4.8 %
(8) CUSTOMER O&M COST PER CUST PER YEAR............	($101.72)
(9) CUSTOMER O&M ESCALATION RATE............	0.0 %
(10) SOCIETAL COST PER CUST PER YEAR............	$0
(11) SOCIETAL BENEFIT PER CUST PER YEAR............	$0
(12) FEDERAL INCOME TAX CREDIT PER CUST............	$0

III. UTILITY MARGINAL COST DATA

(1) IN-SERVICE YEAR FOR AVOIDED GEN, TRN, AND DIST FACILITIES....................	1997
(2) AVOIDED GENERATING UNIT ON-PEAK HOURS.........	93 %
(3) CAPACITY FACTOR (C.F)....................	67.27 %
(4) BASE YEAR....................	1992
(5) AVOIDED FACILITY COST	
A. GEN COST....................	1036 $/KW
B. TRN COST....................	21.375 $/KW
C. DIST COST....................	0 $/KW
ESCALATION RATE....................	4.5 %
D. GEN FIXED O&M COST....................	23.82 $/KW YR
ESCALATION RATE....................	4.75 %
E. TRN FIXED O&M COST....................	0.56 $/KW YR
F. DST FIXED O&M COST....................	0 $/KW YR
ESCALATION RATE....................	4.8 %
G. AVOIDED GEN UNIT VARIABLE O&M....................	0.0211 C/KWH
ESCALATION RATE....................	4.8
H. AVOIDED FUEL....................	2.17202 C/KWH
FUEL ESCALATION RATE....................	6.204 %
(6) ON-PEAK OFF-SYSTEM SALES AVAILABLE AFTER THE YEAR THE UNIT HAS TO BE ON LINE.........	0 %

IV. UTILITY EMBEDDED COST DATA

(1) FUEL COST....................	2.394 C/KWH
(2) NON FUEL COST....................	4.713 C/KWH
(3) KWH ESCALATION RATE....................	2.5894 %

@@@@

#0##

ALL CUSTOMER COST BENEFIT ANALYSIS — PSC FORM 3.4

PROGRAM: DLC-MANDATE — 17-Jun-91

YEAR	(1) TOTAL AVOIDED KW & KWH COSTS $(000)	(2) COMPANYS TOTAL COST $(000)	(3) TOTAL CONSER PROGRAM SAVINGS $(000)	(4) PARTICIPATING CUST SAVINGS IN BILL/TOTAL EMBEDDED COST $(000)	(5) ALL CUSTOMER BENEFIT/ NO GROWTH UTILITY $(000)	(6) PARTICIPATING CUST SAVINGS IN BILL/FUEL COST ONLY $(000)	(7) ALL CUST BENEFIT/ GROWTH UTILITY $(000)
1992	12	479	(467)	28	(494)	9	(476)
1993	24	449	(426)	54	(480)	18	(444)
1994	36	421	(385)	79	(464)	26	(412)
1995	55	585	(529)	112	(642)	38	(567)
1996	89	726	(637)	154	(791)	52	(689)
1997	(723)	719	(1,442)	195	(1,637)	66	(1,508)
1998	(997)	0	(997)	200	(1,197)	67	(1,064)
1999	(2,463)	0	(2,463)	205	(2,669)	69	(2,532)
2000	(4,431)	0	(4,431)	211	(4,642)	71	(4,502)
2001	(4,440)	0	(4,440)	216	(4,656)	73	(4,513)
2002	(5,973)	0	(5,973)	222	(6,195)	75	(6,048)
2003	(7,777)	0	(7,777)	227	(8,004)	77	(7,854)
2004	(8,447)	0	(8,447)	233	(8,680)	79	(8,525)
2005	(10,155)	0	(10,155)	239	(10,394)	81	(10,235)
2006	(13,398)	0	(13,398)	246	(13,644)	83	(13,481)
2007	(13,950)	0	(13,950)	252	(14,202)	85	(14,034)
2008	(18,211)	0	(18,211)	259	(18,469)	87	(18,298)
2009	(23,642)	0	(23,642)	265	(23,907)	89	(23,731)
2010	(31,838)	0	(31,838)	272	(32,110)	92	(31,930)
2011	(38,927)	0	(38,927)	279	(39,206)	94	(39,021)
2012	(47,911)	0	(47,911)	286	(48,198)	96	(48,008)
2013	(51,164)	0	(51,164)	294	(51,458)	99	(51,263)
2014	(65,656)	0	(65,656)	301	(65,957)	102	(65,757)
2015	(85,110)	0	(85,110)	309	(85,419)	104	(85,214)
2016	(94,270)	0	(94,270)	317	(94,587)	107	(94,377)
NOMINAL	(529,266)	3,380	(532,645)	5,456	(538,101)	1,838	(534,483)
NPV:	(141,662)	2,809	(144,471)	2,269	(146,740)	764	(145,275)

#0##

#0##

EMBEDDED COST BENEFIT ANALYSIS TO PARTICIPATING CUSTOMERS PSC FORM CE 3.6
PROGRAM: DLC-MANDATE 17-Jun-91

YEAR	(1) PARTICIPATING CUSTOMER EMBEDDED SAVINGS IN BILLS $(000)	(2) MINUS PARTICIPATING CUSTOMER EQUIPMENT COSTS $(000)	(3) MINUS PARTICIPATING CUSTOMER O & M COSTS $(000)	(4) PARTICIPATING CUSTOMER TAX CREDIT $(000)	(5) PARTICIPATING CUSTOMERS SAVINGS $(000)	(6) UTILITY REBATE/ INCENTIVE $(000)	(7) PARTICIPATING CUSTOMERS SAVINGS WITH UTILITY/REBATE INCENTIVE $(000)
1992	28	0	(381)	0	408	0	408
1993	54	0	(722)	0	775	0	775
1994	79	0	(1,027)	0	1,105	0	1,105
1995	112	0	(1,431)	0	1,543	0	1,543
1996	154	0	(1,911)	0	2,064	0	2,064
1997	195	0	(2,363)	0	2,559	0	2,559
1998	200	0	(2,363)	0	2,564	0	2,564
1999	205	0	(2,363)	0	2,569	0	2,569
2000	211	0	(2,363)	0	2,574	0	2,574
2001	216	0	(2,363)	0	2,580	0	2,580
2002	222	0	(2,363)	0	2,585	0	2,585
2003	227	0	(2,363)	0	2,591	0	2,591
2004	233	0	(2,363)	0	2,597	0	2,597
2005	239	0	(2,363)	0	2,603	0	2,603
2006	246	0	(2,363)	0	2,609	0	2,609
2007	252	0	(2,363)	0	2,615	0	2,615
2008	259	0	(2,363)	0	2,622	0	2,622
2009	265	0	(2,363)	0	2,629	0	2,629
2010	272	0	(2,363)	0	2,635	0	2,635
2011	279	0	(2,363)	0	2,642	0	2,642
2012	286	0	(2,363)	0	2,650	0	2,650
2013	294	0	(2,363)	0	2,657	0	2,657
2014	301	0	(2,363)	0	2,665	0	2,665
2015	309	0	(2,363)	0	2,673	0	2,673
2016	317	0	(2,363)	0	2,681	0	2,681
	--------	--------	--------	--------	--------	--------	--------
NOMINAL	5,456	0	(52,738)	0	58,194	0	58,194
NPV:	2,269	0	(23,609)	0	25,878	0	25,878

#0##

a0eae

FLORIDA SOCIETAL BENEFIT
PROGRAM: DLC-MANDATE

PSC FORM 3.5
17-Jun-91

	----COMPANY EXPENDITURES--			---INDIVIDUAL CUSTOMER AND OTHER COST----------				-------TOTALS-------		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	NON-RECURRING COST $(000)	RE-CURRING COST $(000)	TOTAL COMPANY COST $(000)	PARTICIPATING CUSTOMERS EQUIPMENT COST $(000)	PARTICIPATING CUSTOMERS O & M COST $(000)	OTHER COSTS MINUS OTHER BENEFITS $(000)	TOTAL PARTICIPATING CUSTOMERS AND OTHER COSTS $(000)	TOTAL PROGRAM COST $(000)	TOTAL AVOIDED COSTS $(000)	NET SAVINGS TO FLORIDA $(000)
1992	479	0	479	0	(381)	0	(381)	98	12	(86)
1993	449	0	449	0	(722)	0	(722)	(272)	24	296
1994	421	0	421	0	(1,027)	0	(1,027)	(605)	36	641
1995	585	0	585	0	(1,431)	0	(1,431)	(846)	55	902
1996	726	0	726	0	(1,911)	0	(1,911)	(1,184)	89	1,273
1997	719	0	719	0	(2,363)	0	(2,363)	(1,645)	(723)	922
1998	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(997)	1,366
1999	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(2,463)	(100)
2000	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(4,431)	(2,068)
2001	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(4,440)	(2,077)
2002	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(5,973)	(3,610)
2003	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(7,777)	(5,414)
2004	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(8,447)	(6,083)
2005	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(10,155)	(7,791)
2006	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(13,398)	(11,035)
2007	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(13,950)	(11,586)
2008	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(18,211)	(15,847)
2009	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(23,642)	(21,278)
2010	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(31,838)	(29,475)
2011	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(38,927)	(36,564)
2012	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(47,911)	(45,548)
2013	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(51,164)	(48,801)
2014	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(65,656)	(63,292)
2015	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(85,110)	(82,746)
2016	0	0	0	0	(2,363)	0	(2,363)	(2,363)	(94,270)	(91,907)
NOMINAL	3,380	0	3,380	0	(52,738)	0	(52,738)	(49,358)	(529,266)	(479,908)
NPV:	2,809	0	2,809	0	(23,609)	0	(23,609)	(20,800)	(141,662)	(120,862)

a0eae

#0##

KWH FUEL COSTS SAVINGS DUE TO CONSERVATION PROGRAM PSC FORM CE 3.3
PROGRAM: DLC-MANDATE 17-Jun-91

YEAR	(1) KWH SAVINGS (000)	(2) AVOIDED MARGINAL FUEL $(000)	(3) GAIN IN OFF-SYS SALES $(000)	(4) TOTAL FUEL COST SAVINGS $(000)
1992	412	12	0	12
1993	780	24	0	24
1994	1,110	36	0	36
1995	1,547	55	0	55
1996	2,066	89	0	89
1997	2,556	98	0	98
1998	2,556	138	0	138
1999	2,556	163	0	163
2000	2,556	194	0	194
2001	2,556	202	0	202
2002	2,556	229	0	229
2003	2,556	260	0	260
2004	2,556	277	0	277
2005	2,556	307	0	307
2006	2,556	357	0	357
2007	2,556	375	0	375
2008	2,556	438	0	438
2009	2,556	517	0	517
2010	2,556	629	0	629
2011	2,556	728	0	728
2012	2,556	852	0	852
2013	2,556	905	0	905
2014	2,556	1,098	0	1,098
2015	2,556	1,342	0	1,342
2016	2,556	1,470	0	1,470
	--------	--------	--------	--------
NOMINAL	57,031	10,794	0	10,794
NPV:		3,373	0	3,373

#0##

a0eae

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-MANDATE

PSC FOR CE 3.2.B
17-Jun-91

YEAR	(10) AVOIDED TRANS INVEST $(000)	(11) AVOIDED TRANS VOD FACT	(12) AVOIDED TRNS FIXED COST/YR $(000)	(13) AVOIDED TRANS FIXED O & M $(000)	(14) AVOIDED DIST INVEST $(000)	(15) AVOIDED DIST VOD FACT	(16) AVOIDED DIST FIXED COST/YR $(000)	(17) AVOIDED DIST FIXED O & M $(000)	(18) AVOIDED TRN&DST COST $(000)	(19) TOTAL AVOIDED KW COST $(000)
1992	0	0.0000	0	0	0	0.0000	0	0	0	0
1993	0	0.0000	0	0	0	0.0000	0	0	0	0
1994	0	0.0000	0	0	0	0.0000	0	0	0	0
1995	0	0.0000	0	0	0	0.0000	0	0	0	0
1996	1,003	0.0000	0	0	0	0.0000	0	0	0	0
1997	1,003	0.0446	45	26	0	0.0446	0	0	71	(821)
1998	1,003	0.0466	47	28	0	0.0466	0	0	74	(1,135)
1999	1,003	0.0487	49	29	0	0.0487	0	0	78	(2,626)
2000	1,003	0.0509	51	30	0	0.0509	0	0	81	(4,625)
2001	1,003	0.0532	53	32	0	0.0532	0	0	85	(4,642)
2002	1,003	0.0556	56	33	0	0.0556	0	0	89	(6,202)
2003	1,003	0.0581	58	35	0	0.0581	0	0	93	(8,037)
2004	1,003	0.0607	61	36	0	0.0607	0	0	97	(8,723)
2005	1,003	0.0634	64	38	0	0.0634	0	0	102	(10,462)
2006	1,003	0.0663	66	40	0	0.0663	0	0	106	(13,755)
2007	1,003	0.0693	69	42	0	0.0693	0	0	111	(14,324)
2008	1,003	0.0724	73	44	0	0.0724	0	0	116	(18,649)
2009	1,003	0.0757	76	46	0	0.0757	0	0	122	(24,159)
2010	1,003	0.0791	79	48	0	0.0791	0	0	127	(32,467)
2011	1,003	0.0826	83	50	0	0.0826	0	0	133	(39,655)
2012	1,003	0.0863	87	53	0	0.0863	0	0	139	(48,763)
2013	1,003	0.0902	90	55	0	0.0902	0	0	146	(52,069)
2014	1,003	0.0943	95	58	0	0.0943	0	0	152	(66,753)
2015	1,003	0.0985	99	61	0	0.0985	0	0	159	(86,451)
2016	1,003	0.1030	103	63	0	0.1030	0	0	167	(95,741)
NOMINAL			1,403	846			0	0	2,249	(540,060)
NPV:			512	307			0	0	819	(145,035)

a0eae

a0eae

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-MANDATE

PSC FORM CE 3.2.A
17-Jun-91

YEAR	(1) AVOIDED GEN UNIT INVEST $(000)	(2) AVOIDED GEN UNIT VOD FACT	(3) AVOIDED GEN FIXED COST/YR $(000)	(4) ANNUAL KWH GEN OF AVOIDED UNIT GEN (000)	(5) AVOIDED FUEL COST $(000)	(6a) AVOIDED UNIT FIXED O&M COST $(000)	(6b) AVOIDED UNIT VARIABLE O&M COST $(000)	(7) MINUS THE COST OF ENERGY NOT DISPLACED $(000)	(8) MINUS LOSS IN OFF-SYS SALES $(000)	(9) AVOIDED NET GEN COST $(000)
1992	3,575	0.0000	0	0	0	0	0	0	0	0
1993	9,998	0.0000	0	0	0	0	0	0	0	0
1994	27,302	0.0000	0	0	0	0	0	0	0	0
1995	41.166	0.0000	0	0	0	0	0	0	0	0
1996	50,763	0.0000	0	0	0	0	0	0	0	0
1997	50,763	0.0446	2,265	219,063	6.429	1.117	58	10,761	0	(892)
1998	50,763	0.0466	2,367	219,063	6.828	1,170	61	11,634	0	(1.209)
1999	50,763	0.0487	2.473	219,063	7.251	1,225	64	13,717	0	(2,704)
2000	50,763	0.0509	2,584	219,063	7,701	1.284	67	16.343	0	(4.707)
2001	50,763	0.0532	2.701	219.063	8.179	1.345	70	17,021	0	(4.727)
2002	50.763	0.0556	2,822	219.063	8.686	1.408	74	19.282	0	(6.291)
2003	50.763	0.0581	2.949	219,063	9.225	1,475	77	21.856	0	(8,130)
2004	50.763	0.0607	3.082	219,063	9,798	1.545	81	23.326	0	(8,820)
2005	50.763	0.0634	3.221	219,063	10,406	1.619	84	25.893	0	(10,563)
2006	50,763	0.0663	3,365	219,063	11.051	1.696	89	30,062	0	(13,862)
2007	50,763	0.0693	3.517	219.063	11,737	1.776	93	31.558	0	(14,435)
2008	50,763	0.0724	3.675	219.063	12,465	1.861	97	36,863	0	(18,765)
2009	50,763	0.0757	3.841	219,063	13.238	1.949	102	43.410	0	(24,280)
2010	50,763	0.0791	4,013	219,063	14,059	2,042	107	52.816	0	(32,595)
2011	50,763	0.0826	4.194	219,063	14,932	2.139	112	61,164	0	(39,789)
2012	50,763	0.0863	4,383	219.063	15,858	2.240	117	71.500	0	(48,902)
2013	50.763	0.0902	4.580	219.063	16.842	2,346	122	76.106	0	(52,215)
2014	50.763	0.0943	4.786	219,063	17,887	2.458	128	92,165	0	(66,906)
2015	50,763	0.0985	5,001	219,063	18,996	2,575	134	113.318	0	(86,611)
2016	50,763	0.1030	5.227	219,063	20,175	2.697	141	124.147	0	(95,907)
NOMINAL			71,046	4,381.265	241,744	35,966	1,877	892,941	0	(542.309)
NPV			25,938		85.135	13,061	682	270,670	0	(145,855)

a0eae

2017	20,305	1,529	0	0	0	1,529	1,450	0	2,980	[illegible]	6,463	0,1076
2018	18,855	1,427	0	0	0	1,427	1,450	0	2,878	[illegible]	6,707	0,1124
2019	17,405	1,326	0	0	0	1,326	1,450	0	2,776	[illegible]	6,964	0,1175
2020	15,954	1,224	0	0	0	1,224	1,450	0	2,674	[illegible]	7,233	0,1228
2021	14,504	1,122	0	0	0	1,122	1,450	0	2,572	[illegible]	7,515	0,1283
2022	13,053	1,020	0	0	0	1,020	1,450	0	2,470	[illegible]	7,806	0,1341
2023	11,603	918	0	0	0	918	1,450	0	2,368	[illegible]	7,113	0,1401
2024	10,153	816	0	0	0	816	1,450	0	2,266	[illegible]	7,433	0,1464
2025	8,702	714	0	0	0	714	1,450	0	2,164	[illegible]	7,767	0,1530
2026	7,252	612	0	0	0	612	1,450	0	2,062	[illegible]	8,117	0,1599
2027	5,802	510	0	0	0	510	1,450	0	1,960	[illegible]	8,483	0,1671
2028	4,351	408	0	0	0	408	1,450	0	1,858	[illegible]	8,864	0,[illegible]46
2029	2,901	306	0	0	0	306	1,450	0	1,756	[illegible]	9,262	0,[illegible]25
2030	1,450	204	0	0	0	204	1,450	0	1,654	[illegible]	9,679	0,[illegible]07
2031	0	102	0	0	0	102	1,450	0	1,552	[illegible]	10,119	0,[illegible]93

Nominal:	114,999	104,962
NPV:	38,684	38,684
K Factor:	1,0703	

A0#A#

a0ese

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-MANDATE

PSC FORM CE 3.1.8
17-Jun-91

VI. FINANCIAL DATA

(1) GENERATION				
(1A) DEBT.........%	100	COST	7.03 %	
(1B) PREFERRED... %	0	COST	0 %	
(1C) EQUITY.......%	0	COST	0 %	
(1D) EFFECTIVE TAX RATE.............			0 %	
(1E) GENERATOR TAX LIFE.............			35 YEARS	
(1F) INSURANCE AND OTHER TAXES.......			0 %	

(2) TRANSMISSION AND DISTRIBUTION			
(2A) DEBT..............%	100	COST	7.03 %
(2B) PREFERRED.........%	0	COST	0 %
(2C) EQUITY............%	0	COST	0 %
(2D) EFFECTIVE TAX RATE......................			0 %
(2E) TRANSMISSION TAX LIFE....................			35 YEARS
(2F) INSURANCE AND OTHER TAXES................			0 %

(3) DISCOUNT RATE	
(3A) UTILITY........................	7.03 %
(3B) CUSTOMER.......................	10.2 %
(3C) K Factor for Avoided Gen Unit [Calc.].....	1.0703
(3D) K Factor for Avoided T & D [Calc.]........	1.0703

VII. DERIVATION OF CAPITAL CARRYING CHARGES FOR AVOIDED GENERATION

YEAR	(1) AVOIDED ELECTRIC PLANT IN SERVICE $(000)	(2) DEBT $(000)	(3) PREFERRED $(000)	(4) EQUITY $(000)	(5) TAX $(000)	(6) TOTAL DEBT PREFERRED EQUITY & TAX $(000)	(7) DEPREC $(000)	(8) INSURANCE & OTHER TAXES $(000)	(9) TOTAL ANNUAL FIXED COST $(000)	(10) AVOIDED GEN UNIT CCR	(11) VALUE OF DEFERRAL $(000)	VALUE OF DEFERRAL FACTOR
1992	3,575	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1993	9,998	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1994	27,302	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1995	41,166	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1996	50,763	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1997	49,313	3,569	0	0	0	3,569	1,450	0	5,019	0.0989	2,265	0.0444
1998	47,863	3,467	0	0	0	3,467	1,450	0	4,917	0.0969	2,367	0.0464
1999	46,412	3,365	0	0	0	3,365	1,450	0	4,815	0.0949	2,472	0.0487
2000	44,962	3,263	0	0	0	3,263	1,450	0	4,713	0.0928	2,584	0.0506
2001	43,511	3,161	0	0	0	3,161	1,450	0	4,611	0.0908	2,701	0.0533
2002	42,061	3,059	0	0	0	3,059	1,450	0	4,509	0.0888	2,822	0.0556
2003	40,611	2,957	0	0	0	2,957	1,450	0	4,407	0.0868	2,948	0.0581
2004	39,160	2,855	0	0	0	2,855	1,450	0	4,305	0.0848	3,082	0.0607
2005	37,710	2,753	0	0	0	2,753	1,450	0	4,203	0.0828	3,221	0.0634
2006	36,260	2,651	0	0	0	2,651	1,450	0	4,101	0.0808	3,365	0.0662
2007	34,809	2,549	0	0	0	2,549	1,450	0	3,999	0.0788	3,515	0.0692
2008	33,359	2,447	0	0	0	2,447	1,450	0	3,897	0.0768	3,675	0.0724
2009	31,908	2,345	0	0	0	2,345	1,450	0	3,796	0.0748	3,841	0.0757
2010	30,458	2,243	0	0	0	2,243	1,450	0	3,694	0.0728	4,013	0.0791
2011	29,008	2,141	0	0	0	2,141	1,450	0	3,592	0.0708	4,194	0.0826
2012	27,557	2,039	0	0	0	2,039	1,450	0	3,490	0.0687	4,383	0.0863
2013	26,107	1,937	0	0	0	1,937	1,450	0	3,388	0.0667	4,580	0.0902
2014	24,656	1,835	0	0	0	1,835	1,450	0	3,286	0.0647	4,786	0.0943
2015	23,206	1,733	0	0	0	1,733	1,450	0	3,184	0.0627	5,001	0.0985
2016	21,[illegible]56	1,631	0	0	0	1,631	1,450	0	3,082	0.0607	5,227	0.1030

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-MANDATE

V. YEARLY INPUT DATA

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	CUMULATIVE PARTICIPATING CUSTOMERS	MARGINAL FUEL COST WITH AVOIDED GENERATING UNIT				MARGINAL FUEL COST W/O AVOIDED GEN UNIT			
		UTILITY		STATE		UTILITY		STATE	
YEAR		ON-PEAK (C/KWH)	OFF PEAK (C/KWH)	ON PEAK (C/KWH)	OFF PEAK (C/KWH)	ON-PEAK (C/KWH)	OFF PEAK (C/KWH)	ON PEAK (C/KWH)	OFF PEAK (C/KWH)
1992	3.742	3.02	2.53	3.02	2.53	3.02	2.53	3.02	2.53
1993	7,094	3.02	2.57	3.02	2.57	3.02	2.57	3.02	2.57
1994	10,094	3.25	2.76	3.25	2.76	3.25	2.76	3.25	2.76
1995	14,068	3.58	3.12	3.58	3.12	3.58	3.02	3.58	3.02
1996	18.762	4.32	3.49	4.32	3.49	4.32	3.49	4.32	3.49
1997	23,234	3.85	3.03	3.85	3.03	4.99	3.88	4.99	3.88
1998	23,234	4.13	3.33	4.13	3.33	5.39	4.26	5.39	4.26
1999	23,234	4.59	3.61	4.59	3.61	6.37	4.81	6.37	4.81
2000	23,234	5.17	4.02	5.17	4.02	7.60	5.58	7.60	5.58
2001	23,234	6.26	4.44	6.26	4.44	7.90	6.06	7.90	6.06
2002	23,234	6.95	4.88	6.95	4.88	8.95	6.82	8.95	6.82
2003	23,234	7.81	5.28	7.81	5.28	10.16	7.58	10.16	7.58
2004	23,234	8.33	5.94	8.33	5.94	10.82	8.31	10.82	8.31
2005	23,234	9.25	6.48	9.25	6.48	12.01	9.24	12.01	9.24
2006	23,234	10.54	7.11	10.54	7.11	13.97	10.44	13.97	10.44
2007	23,234	11.68	7.82	11.68	7.82	14.66	11.03	14.66	11.03
2008	23,234	13.12	8.78	13.12	8.78	17.13	12.82	17.13	12.82
2009	23,234	10.54	9.36	10.54	9.36	20.23	14.38	20.23	14.38
2010	23,234	11.77	7.49	11.77	7.49	24.62	17.37	24.62	17.37
2011	23,234	13.85	8.24	13.85	8.24	28.49	20.41	28.49	20.41
2012	23,234	15.53	9.45	15.53	9.45	33.33	23.49	33.33	23.49
2013	23,234	17.77	10.47	17.77	10.47	35.43	25.62	35.43	25.62
2014	23,234	13.10	11.88	13.10	11.88	42.95	30.46	42.95	30.46
2015	23,234	15.67	9.18	15.67	9.18	52.49	41.57	52.49	41.57
2016	23,234	12.00	10.60	12.00	10.60	57.53	45.28	57.53	45.28

PSC FORM CE 3.1.A
PAGE 1 OF 2
17-Jun-91

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-MANDATE

VOD: 20 YR PGM: 35 YR GEN TAX LIFE

I. CONSERVATION PROGRAM OPERATIONAL AND COST DATA

(1) GEN REDUCTION PER CUSTOMER	1.60 KW and 110 KWH
(2) PEAK REDUCTION PER CUSTOMER	1.90 KW
(3) KWH REDUCTION PER CUSTOMER	104.00 KWH
(4) KWH REDUCTION THAT IS ON PEAK	100 %
(5) TOTAL PARTICIPATING CUSTOMERS	23,234

II. CONSERVATION PROGRAM COST DATA

(1) UTILITY NON RECURRING COST PER CUSTOMER	$128
(2) UTILITY NON-RECURRING COST ESCALATION RATE	4.8 %
(3) UTILITY RECURRING COST PER CUST PER YEAR	$0
(4) UTILITY RECURRING COST ESCALATION RATE	0.5 %
(5) UTILITY REBATE/FINANCIAL INCENTIVE	$0
(6) CUSTOMER EQUIPMENT COST PER CUST	$0
(7) CUSTOMER EQUIPMENT ESCALATION RATE	4.8 %
(8) CUSTOMER O&M COST PER CUST PER YEAR	($101.72)
(9) CUSTOMER O&M ESCALATION RATE	0.0 %
(10) SOCIETAL COST PER CUST PER YEAR	$0
(11) SOCIETAL BENEFIT PER CUST PER YEAR	$0
(12) FEDERAL INCOME TAX CREDIT PER CUST	$0

III. UTILITY MARGINAL COST DATA

(1) IN-SERVICE YEAR FOR AVOIDED GEN, TRN, AND DIST FACILITIES	1997
(2) AVOIDED GENERATING UNIT ON-PEAK HOURS	93 %
(3) CAPACITY FACTOR (C.F)	67.27 %
(4) BASE YEAR	1992
(5) AVOIDED FACILITY COST	
A. GEN COST	1036 $/KW
B. TRN COST	21.375 $/KW
C. DIST COST	0 $/KW
ESCALATION RATE	4.5 %
D. GEN FIXED O&M COST	23.82 $/KW YR
ESCALATION RATE	4.75 %
E. TRN FIXED O&M COST	0.56 $/KW YR
F. DST FIXED O&M COST	0 $/KW YR
ESCALATION RATE	4.8 %
G. AVOIDED GEN UNIT VARIABLE O&M	0.0211 C/KWH
ESCALATION RATE	4.8
H. AVOIDED FUEL	2.17202 C/KWH
FUEL ESCALATION RATE	6.204 %
(6) ON-PEAK OFF-SYSTEM SALES AVAILABLE AFTER THE YEAR THE UNIT WAS TO BE ON LINE	0 %

IV. UTILITY EMBEDDED COST DATA

(1) FUEL COST	2.394 C/KWH
(2) NON FUEL COST	4.713 C/KWH
(3) KWH ESCALATION RATE	2.5894 %

EMBEDDED COST BENEFIT ANALYSIS TO PARTICIPATING CUSTOMERS PSC FORM CE 3.6
PROGRAM: DLC-0.5 FPC 17-Jun-91

YEAR	(1) PARTICIPATING CUSTOMER EMBEDDED SAVINGS IN BILLS $(000)	(2) MINUS PARTICIPATING CUSTOMER EQUIPMENT COSTS $(000)	(3) MINUS PARTICIPATING CUSTOMER O & M COSTS $(000)	(4) PARTICIPATING CUSTOMER TAX CREDIT $(000)	(5) PARTICIPATING CUSTOMERS SAVINGS $(000)	(6) UTILITY REBATE/ INCENTIVE $(000)	(7) PARTICIPATING CUSTOMERS SAVINGS WITH UTILITY/REBATE INCENTIVE $(000)
1992	15	0	(213)	0	228	0	228
1993	57	0	(758)	0	815	0	815
1994	84	0	(1,103)	0	1,188	0	1,188
1995	121	0	(1,545)	0	1,666	0	1,666
1996	172	0	(2,131)	0	2,303	0	2,303
1997	220	0	(2,669)	0	2,890	0	2,890
1998	226	0	(2,669)	0	2,896	0	2,896
1999	232	0	(2,669)	0	2,901	0	2,901
2000	238	0	(2,669)	0	2,907	0	2,907
2001	244	0	(2,669)	0	2,914	0	2,914
2002	250	0	(2,669)	0	2,920	0	2,920
2003	257	0	(2,669)	0	2,926	0	2,926
2004	264	0	(2,669)	0	2,933	0	2,933
2005	270	0	(2,669)	0	2,940	0	2,940
2006	277	0	(2,669)	0	2,947	0	2,947
2007	285	0	(2,669)	0	2,954	0	2,954
2008	292	0	(2,669)	0	2,961	0	2,961
2009	300	0	(2,669)	0	2,969	0	2,969
2010	307	0	(2,669)	0	2,977	0	2,977
2011	315	0	(2,669)	0	2,985	0	2,985
2012	323	0	(2,669)	0	2,993	0	2,993
2013	332	0	(2,669)	0	3,001	0	3,001
2014	340	0	(2,669)	0	3,010	0	3,010
2015	349	0	(2,669)	0	3,019	0	3,019
2016	358	0	(2,669)	0	3,028	0	3,028
NOMINAL	6,131	0	(59,139)	0	65,270	0	65,270
NPV:	2,533	0	(26,269)	0	28,802	0	28,802

#0##0

FLORIDA SOCIETAL BENEFIT
PROGRAM: DLC-0.5 FPC

PSC FORM 3.5
17-Jun-91

	----COMPANY EXPENDITURES--			---INDIVIDUAL CUSTOMER AND OTHER COST----------				-------TOTALS-------		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	NON-RECURRING COST $(000)	RE-CURRING COST $(000)	TOTAL COMPANY COST $(000)	PARTICIPATING CUSTOMERS EQUIPMENT COST $(000)	PARTICIPATING CUSTOMERS O & M COST $(000)	OTHER COSTS MINUS OTHER BENEFITS $(000)	TOTAL PARTICIPATING CUSTOMERS AND OTHER COSTS $(000)	TOTAL PROGRAM COST $(000)	TOTAL AVOIDED COSTS $(000)	NET SAVINGS TO FLORIDA $(000)
1992	268	118	386	0	(213)	0	(213)	173	7	(166)
1993	719	423	1,142	0	(758)	0	(758)	384	25	(359)
1994	476	619	1,095	0	(1,103)	0	(1,103)	(8)	39	47
1995	638	871	1,509	0	(1,545)	0	(1,545)	(36)	60	95
1996	889	1208	2,096	0	(2,131)	0	(2,131)	(35)	100	134
1997	854	1520	2,374	0	(2,669)	0	(2,669)	(295)	(817)	(522)
1998	0	1528	1,528	0	(2,669)	0	(2,669)	(1,142)	(1,126)	16
1999	0	1535	1,535	0	(2,669)	0	(2,669)	(1,134)	(2,782)	(1,648)
2000	0	1543	1,543	0	(2,669)	0	(2,669)	(1,126)	(5,005)	(3,879)
2001	0	1551	1,551	0	(2,669)	0	(2,669)	(1,119)	(5,015)	(3,896)
2002	0	1559	1,559	0	(2,669)	0	(2,669)	(1,111)	(6,747)	(5,636)
2003	0	1566	1,566	0	(2,669)	0	(2,669)	(1,103)	(8,784)	(7,681)
2004	0	1574	1,574	0	(2,669)	0	(2,669)	(1,095)	(9,540)	(8,445)
2005	0	1582	1,582	0	(2,669)	0	(2,669)	(1,087)	(11,470)	(10,382)
2006	0	1590	1,590	0	(2,669)	0	(2,669)	(1,079)	(15,133)	(14,054)
2007	0	1598	1,598	0	(2,669)	0	(2,669)	(1,072)	(15,756)	(14,685)
2008	0	1606	1,606	0	(2,669)	0	(2,669)	(1,064)	(20,569)	(19,506)
2009	0	1614	1,614	0	(2,669)	0	(2,669)	(1,056)	(26,704)	(25,648)
2010	0	1622	1,622	0	(2,669)	0	(2,669)	(1,047)	(35,961)	(34,914)
2011	0	1630	1,630	0	(2,669)	0	(2,669)	(1,039)	(43,968)	(42,929)
2012	0	1638	1,638	0	(2,669)	0	(2,669)	(1,031)	(54,116)	(53,085)
2013	0	1646	1,646	0	(2,669)	0	(2,669)	(1,023)	(57,790)	(56,767)
2014	0	1655	1,655	0	(2,669)	0	(2,669)	(1,015)	(74,159)	(73,144)
2015	0	1663	1,663	0	(2,669)	0	(2,669)	(1,006)	(96,132)	(95,126)
2016	0	1671	1,671	0	(2,669)	0	(2,669)	(998)	(106,479)	(105,481)
	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
NOMINAL	3,844	35,131	38,975	0	(59,139)	0	(59,139)	(20,164)	(597,825)	(577,661)
NPV:	3,161	15,388	18,549	0	(26,269)	0	(26,269)	(7,720)	(160,023)	(152,303)

#0##0

a0eae

ALL CUSTOMER COST BENEFIT ANALYSIS — FSC FORM 3.4
PROGRAM: DLC-0.5 FPC — 17-Jun-91

YEAR	(1) TOTAL AVOIDED KW & KWH COSTS $(000)	(2) COMPANYS TOTAL COST $(000)	(3) TOTAL CONSER PROGRAM SAVINGS $(000)	(4) PARTICIPATING CUST SAVINGS IN BILL/TOTAL EMBEDDED COST $(000)	(5) ALL CUSTOMER BENEFIT/ NO GROWTH UTILITY $(000)	(6) PARTICIPATING CUST SAVINGS IN BILL/FUEL COST ONLY $(000)	(7) ALL CUST BENEFIT/ GROWTH UTILITY $(000)
1992	7	386	(379)	15	(395)	5	(384)
1993	25	1,142	(1,117)	57	(1,174)	19	(1,137)
1994	39	1,095	(1,057)	84	(1,141)	28	(1,085)
1995	60	1,509	(1,449)	121	(1,570)	41	(1,490)
1996	100	2,096	(1,997)	172	(2,168)	58	(2,055)
1997	(817)	2,374	(3,191)	220	(3,412)	74	(3,265)
1998	(1,126)	1,528	(2,654)	226	(2,880)	76	(2,730)
1999	(2,782)	1,535	(4,318)	232	(4,550)	78	(4,396)
2000	(5,005)	1,543	(6,548)	238	(6,786)	80	(6,628)
2001	(5,015)	1,551	(6,566)	244	(6,810)	82	(6,648)
2002	(6,747)	1,559	(8,306)	250	(8,556)	84	(8,390)
2003	(8,784)	1,566	(10,351)	257	(10,607)	87	(10,437)
2004	(9,540)	1,574	(11,115)	264	(11,378)	89	(11,203)
2005	(11,470)	1,582	(13,052)	270	(13,322)	91	(13,143)
2006	(15,133)	1,590	(16,723)	277	(17,001)	93	(16,817)
2007	(15,756)	1,598	(17,354)	285	(17,639)	96	(17,450)
2008	(20,569)	1,606	(22,175)	292	(22,467)	98	(22,274)
2009	(26,704)	1,614	(28,318)	300	(28,617)	101	(28,418)
2010	(35,961)	1,622	(37,583)	307	(37,891)	104	(37,687)
2011	(43,968)	1,630	(45,598)	315	(45,914)	106	(45,705)
2012	(54,116)	1,638	(55,754)	323	(56,078)	109	(55,863)
2013	(57,790)	1,646	(59,437)	332	(59,768)	112	(59,548)
2014	(74,159)	1,655	(75,813)	340	(76,154)	115	(75,928)
2015	(96,132)	1,663	(97,795)	349	(98,144)	118	(97,913)
2016	(106,479)	1,671	(108,150)	358	(108,509)	121	(108,271)
	--------	--------	--------	--------	--------	--------	--------
NOMINAL	(597,825)	38,975	(636,800)	6,131	(642,931)	2,065	(638,865)
NPV:	(160,022)	18,549	(178,571)	2,533	(181,105)	853	(179,425)

a0eae

KWH FUEL COSTS SAVINGS DUE TO CONSERVATION PROGRAM   PSC FORM CE 3.3
PROGRAM: DLC-0.5 FPC   17-Jun-91

YEAR	(1) KWH SAVINGS (000)	(2) AVOIDED MARGINAL FUEL $(000)	(3) GAIN IN OFF-SYS SALES $(000)	(4) TOTAL FUEL COST SAVINGS $(000)
1992	230	7	0	7
1993	820	25	0	25
1994	1,193	39	0	39
1995	1,670	60	0	60
1996	2,305	100	0	100
1997	2,887	111	0	111
1998	2,887	156	0	156
1999	2,887	184	0	184
2000	2,887	219	0	219
2001	2,887	228	0	228
2002	2,887	258	0	258
2003	2,887	293	0	293
2004	2,887	312	0	312
2005	2,887	347	0	347
2006	2,887	403	0	403
2007	2,887	423	0	423
2008	2,887	494	0	494
2009	2,887	584	0	594
2010	2,887	711	0	711
2011	2,887	822	0	822
2012	2,887	962	0	962
2013	2,887	1,023	0	1,023
2014	2,887	1,240	0	1,240
2015	2,887	1,515	0	1,515
2016	2,887	1,661	0	1,661
	--------	--------	--------	--------
NOMINAL	63,953	12,177	0	12,177
NPV:		3,796	0	3,796

#0##

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-0.5 FPC

PSC FOR CE 7.2.5
17-Jun-91

YEAR	(10) AVOIDED TRANS INVEST $(000)	(11) AVOIDED TRANS VOD FACT	(12) AVOIDED TRNS FIXED COST/YR $(000)	(13) AVOIDED TRANS FIXED O & M $(000)	(14) AVOIDED DIST INVEST $(000)	(15) AVOIDED DIST VOD FACT	(16) AVOIDED DIST FIXED COST/YR $(000)	(17) AVOIDED DIST FIXED O & M $(000)	(18) AVOIDED TRN&DST COST $(000)	(19) TOTAL AVOIDED KW COST $(000)
1992	0	0.0000	0	0	0	0.0000	0	0	0	0
1993	0	0.0000	0	0	0	0.0000	0	0	0	0
1994	0	0.0000	0	0	0	0.0000	0	0	0	0
1995	0	0.0000	0	0	0	0.0000	0	0	0	0
1996	1,133	0.0000	0	0	0	0.0000	0	0	0	0
1997	1,133	0.0446	51	30	0	0.0446	0	0	80	(928)
1998	1,133	0.0466	53	31	0	0.0466	0	0	84	(1,282)
1999	1,133	0.0487	55	33	0	0.0487	0	0	88	(2,966)
2000	1,133	0.0509	58	34	0	0.0509	0	0	92	(5,224)
2001	1,133	0.0532	60	36	0	0.0532	0	0	96	(5,243)
2002	1,133	0.0556	63	37	0	0.0556	0	0	100	(7,005)
2003	1,133	0.0581	66	39	0	0.0581	0	0	105	(9,077)
2004	1,133	0.0607	69	41	0	0.0607	0	0	110	(9,853)
2005	1,133	0.0634	72	43	0	0.0634	0	0	115	(11,817)
2006	1,133	0.0663	75	45	0	0.0663	0	0	120	(15,537)
2007	1,133	0.0693	78	47	0	0.0693	0	0	126	(16,179)
2008	1,133	0.0724	82	49	0	0.0724	0	0	131	(21,064)
2009	1,133	0.0757	86	52	0	0.0757	0	0	137	(27,287)
2010	1,133	0.0791	90	54	0	0.0791	0	0	144	(36,672)
2011	1,133	0.0826	94	57	0	0.0826	0	0	150	(44,791)
2012	1,133	0.0863	98	59	0	0.0863	0	0	157	(55,078)
2013	1,133	0.0902	102	62	0	0.0902	0	0	164	(58,813)
2014	1,133	0.0943	107	65	0	0.0943	0	0	172	(75,399)
2015	1,133	0.0985	112	68	0	0.0985	0	0	180	(97,648)
2016	1,133	0.1030	117	72	0	0.1030	0	0	188	(106,140)
			--------	--------			--------	--------	--------	--------
NOMINAL			1,585	955			0	0	2,540	(610,002)
NPV:			579	347			0	0	926	(163,819)

#0##

AVOIDED CAPACITY COST BENEFITS
PROGRAM: DLC-0.5 FPC

PSC FORM CE 3.2.A
17-Jun-91

YEAR	(1) AVOIDED GEN UNIT INVEST $(000)	(2) AVOIDED GEN UNIT VOD FACT	(3) AVOIDED GEN FIXED COST/YR $(000)	(4) ANNUAL KWH GEN OF AVOIDED UNIT GEN (000)	(5) AVOIDED FUEL COST $(000)	(6a) AVOIDED UNIT FIXED O&M COST $(000)	(6b) AVOIDED UNIT VARIABLE O&M COST $(000)	(7) MINUS THE COST OF ENERGY NOT DISPLACED $(000)	(8) MINUS LOSS IN OFF-SYS SALES $(000)	(9) AVOIDED NET GEN COST $(000)
1992	4,038	0.0000	0	0	0	0	0	0	0	0
1993	11,293	0.0000	0	0	0	0	0	0	0	0
1994	30,838	0.0000	0	0	0	0	0	0	0	0
1995	46,497	0.0000	0	0	0	0	0	0	0	0
1996	57,338	0.0000	0	0	0	0	0	0	0	0
1997	57,338	0.0446	2,558	247,434	7,262	1,261	66	12,155	0	(1,008)
1998	57,338	0.0466	2,673	247,434	7,712	1,321	69	13,141	0	(1,366)
1999	57,338	0.0487	2,793	247,434	8,190	1,384	72	15,494	0	(3,054)
2000	57,338	0.0509	2,919	247,434	8,699	1,450	76	18,459	0	(5,316)
2001	57,338	0.0532	3,050	247,434	9,238	1,519	79	19,226	0	(5,339)
2002	57,338	0.0556	3,188	247,434	9,811	1,591	83	21,779	0	(7,106)
2003	57,338	0.0581	3,331	247,434	10,420	1,666	87	24,687	0	(9,182)
2004	57,338	0.0607	3,481	247,434	11,067	1,746	91	26,347	0	(9,963)
2005	57,338	0.0634	3,638	247,434	11,753	1,828	95	29,246	0	(11,931)
2006	57,338	0.0663	3,801	247,434	12,482	1,915	100	33,956	0	(15,657)
2007	57,338	0.0693	3,972	247,434	13,257	2,006	105	35,645	0	(16,305)
2008	57,338	0.0724	4,151	247,434	14,079	2,102	110	41,637	0	(21,195)
2009	57,338	0.0757	4,338	247,434	14,953	2,201	115	49,032	0	(27,425)
2010	57,338	0.0791	4,533	247,434	15,880	2,306	120	59,656	0	(36,816)
2011	57,338	0.0826	4,737	247,434	16,866	2,415	126	69,085	0	(44,941)
2012	57,338	0.0863	4,950	247,434	17,912	2,530	132	80,760	0	(55,236)
2013	57,338	0.0902	5,173	247,434	19,023	2,650	138	85,962	0	(58,977)
2014	57,338	0.0943	5,406	247,434	20,203	2,776	145	104,101	0	(75,571)
2015	57,338	0.0985	5,649	247,434	21,457	2,908	152	127,993	0	(97,827)
2016	57,338	0.1030	5,903	247,434	22,788	3,046	159	140,225	0	(108,326)
NOMINAL			80,247	4,948,676	273,052	40,623	2,121	1,008,584	0	(612,542)
NPV			29,297		96,161	14,752	770	305,724	0	(164,744)

2017	22,935	1,728	0	0	0	1,728	1,638	0	3,366	0.0587	6,169	0.1076
2018	21,297	1,612	0	0	0	1,612	1,638	0	3,251	0.0567	6,447	0.1124
2019	19,659	1,497	0	0	0	1,497	1,638	0	3,135	0.0547	6,737	0.1175
2020	18,020	1,382	0	0	0	1,382	1,638	0	3,020	0.0527	7,040	0.1228
2021	16,382	1,267	0	0	0	1,267	1,638	0	2,905	0.0507	7,357	0.1283
2022	14,744	1,152	0	0	0	1,152	1,638	0	2,790	0.0487	7,688	0.1341
2023	13,106	1,037	0	0	0	1,037	1,638	0	2,675	0.0466	8,034	0.1401
2024	11,468	921	0	0	0	921	1,638	0	2,560	0.0446	8,395	0.1464
2025	9,829	806	0	0	0	806	1,638	0	2,444	0.0426	8,773	0.1530
2026	8,191	691	0	0	0	691	1,638	0	2,329	0.0406	9,168	0.1599
2027	6,553	576	0	0	0	576	1,638	0	2,214	0.0386	9,580	0.1671
2028	4,915	461	0	0	0	461	1,638	0	2,099	0.0366	10,011	0.1746
2029	3,276	346	0	0	0	346	1,638	0	1,984	0.0346	10,462	0.1825
2030	1,638	230	0	0	0	230	1,638	0	1,869	0.0326	10,933	0.1907
2031	0	115	0	0	0	115	1,638	0	1,753	0.0306	11,425	0.1993
								Nominal:	129,893		208,464	
								NPV:	43,694		43,694	
								K Factor:	1.0703			

a0###

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-0.5 FPC

PSC FORM CE 3.1.B
17-Jun-91

VI. FINANCIAL DATA

(1) GENERATION				(2) TRANSMISSION AND DISTRIBUTION			
(1A) DEBT.........%	100	COST	7.03 %	(2A) DEBT.............%	100	COST	7.03 %
(1B) PREFERRED... %	0	COST	0 %	(2B) PREFERRED.........%	0	COST	0 %
(1C) EQUITY.......%	0	COST	0 %	(2C) EQUITY............%	0	COST	0 %
(1D) EFFECTIVE TAX RATE.............			0 %	(2D) EFFECTIVE TAX RATE........................			0 %
(1E) GENERATOR TAX LIFE.............			35 YEARS	(2E) TRANSMISSION TAX LIFE......................			35 YEARS
(1F) INSURANCE AND OTHER TAXES.......			0 %	(2F) INSURANCE AND OTHER TAXES.................			0 %

(3) DISCOUNT RATE			
(3A) UTILITY.........................	7.03 %	(3C) K Factor for Avoided Gen Unit [Calc.].....	1.0703
(3B) CUSTOMER........................	10.2 %	(3D) K Factor for Avoided T & D [Calc.]........	1.0703

VII. DERIVATION OF CAPITAL CARRYING CHARGES FOR AVOIDED GENERATION

YEAR	(1) AVOIDED ELECTRIC PLANT IN SERVICE $(000)	(2) DEBT $(000)	(3) PREFERRED $(000)	(4) EQUITY $(000)	(5) TAX $(000)	(6) TOTAL DEBT PREFERRED EQUITY & TAX $(000)	(7) DEPREC $(000)	(8) INSURANCE & OTHER TAXES $(000)	(9) TOTAL ANNUAL FIXED COST $(000)	(10) AVOIDED GEN UNIT CCR	(11) VALUE OF DEFERRAL $(000)	VALUE OF DEFERRAL FACTOR
1992	4,038	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1993	11,293	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1994	30,838	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1995	46,497	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1996	57,338	0	0	0	0	0	0	0	0	0.0000	0	0.0000
1997	55,699	4,031	0	0	0	4,031	1,638	0	5,669	0.0989	2,558	0.0446
1998	54,061	3,916	0	0	0	3,916	1,638	0	5,554	0.0969	2,673	0.0466
1999	52,423	3,801	0	0	0	3,801	1,638	0	5,439	0.0949	2,793	0.0487
2000	50,785	3,685	0	0	0	3,685	1,638	0	5,324	0.0928	2,919	0.0509
2001	49,147	3,570	0	0	0	3,570	1,639	0	5,208	0.0908	3,050	0.0532
2002	47,508	3,455	0	0	0	3,455	1,638	0	5,093	0.0888	3,188	0.0556
2003	45,870	3,340	0	0	0	3,340	1,639	0	4,978	0.0868	3,331	0.0581
2004	44,232	3,225	0	0	0	3,225	1,638	0	4,863	0.0848	3,481	0.0607
2005	42,594	3,110	0	0	0	3,110	1,638	0	4,748	0.0828	3,638	0.0634
2006	40,955	2,994	0	0	0	2,994	1,638	0	4,633	0.0808	3,801	0.0663
2007	39,317	2,879	0	0	0	2,879	1,638	0	4,517	0.0788	3,972	0.0693
2008	37,679	2,764	0	0	0	2,764	1,638	0	4,402	0.0768	4,151	0.0724
2009	36,041	2,649	0	0	0	2,649	1,638	0	4,287	0.0748	4,338	0.0757
2010	34,403	2,534	0	0	0	2,534	1,638	0	4,172	0.0728	4,533	0.0791
2011	32,764	2,419	0	0	0	2,419	1,639	0	4,057	0.0708	4,737	0.0826
2012	31,126	2,303	0	0	0	2,303	1,638	0	3,942	0.0687	4,950	0.0863
2013	29,488	2,188	0	0	0	2,188	1,638	0	3,826	0.0667	5,173	0.0902
2014	27,85[illegible]	2,073	0	0	0	2,073	1,639	0	3,711	0.0647	5,406	0.0943
2015	26,211	1,958	0	0	0	1,958	1,638	0	3,596	0.0627	5,649	0.0985
2016	24,573	1,843	0	0	0	1,843	1,638	0	3,481	0.0607	5,903	0.1030

@@@@

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-0.5 FPC

PSC FORM CE 3.1.A

17-Jun-91

V. YEARLY INPUT DATA

YEAR	(1) CUMULATIVE PARTICIPATING CUSTOMERS	(2) MARGINAL FUEL COST WITH AVOIDED GENERATING UNIT -----UTILITY---- ON-PEAK (C/KWH)	(3) OFF PEAK (C/KWH)	(4) -----STATE------- ON PEAK (C/KWH)	(5) OFF PEAK (C/KWH)	(6) MARGINAL FUEL COST W/O AVOIDED GEN UNIT -----UTILITY---- ON-PEAK (C/KWH)	(7) OFF PEAK (C/KWH)	(8) -----STATE-------- ON PEAK (C/KWH)	(9) OFF PEAK (C/KWH)
1992	2,093	3.02	2.53	3.02	2.53	3.02	2.53	3.02	2.53
1993	7,455	3.02	2.57	3.02	2.57	3.02	2.57	3.02	2.57
1994	10,847	3.25	2.76	3.25	2.76	3.25	2.76	3.25	2.76
1995	15.185	3.58	3.12	3.58	3.12	3.58	3.02	3.58	3.02
1996	20,952	4.32	3.49	4.32	3.49	4.32	3.49	4.32	3.49
1997	26,243	3.85	3.03	3.85	3.03	4.99	3.88	4.99	3.88
1998	26,243	4.13	3.33	4.13	3.33	5.39	4.26	5.39	4.26
1999	26,243	4.59	3.61	4.59	3.61	6.37	4.81	6.37	4.81
2000	26,243	5.17	4.02	5.17	4.02	7.60	5.58	7.60	5.58
2001	26,243	6.26	4.44	6.26	4.44	7.90	6.06	7.90	6.06
2002	26.243	6.95	4.88	6.95	4.88	8.95	6.82	8.95	6.82
2003	26,243	7.81	5.28	7.81	5.28	10.16	7.58	10.16	7.58
2004	26,243	8.33	5.94	8.33	5.94	10.82	8.31	10.82	8.31
2005	26,243	9.25	6.48	9.25	6.48	12.01	9.24	12.01	9.24
2006	26,243	10.54	7.11	10.54	7.11	13.97	10.44	13.97	10.44
2007	26,243	11.68	7.82	11.68	7.82	14.66	11.03	14.66	11.03
2008	26,243	13.12	8.78	13.12	8.78	17.13	12.82	17.13	12.82
2009	26,243	10.54	9.36	10.54	9.36	20.23	14.38	20.23	14.38
2010	26,243	11.77	7.49	11.77	7.49	24.62	17.37	24.62	17.37
2011	26.243	13.85	8.24	13.85	8.24	28.49	20.41	28.49	20.41
2012	26,243	15.53	9.45	15.53	9.45	33.33	23.49	33.33	23.49
2013	26,243	17.77	10.47	17.77	10.47	35.43	25.62	35.43	25.62
2014	26,243	13.10	11.88	13.10	11.88	42.95	30.46	42.95	30.46
2015	26,243	15.67	9.18	15.67	9.18	52.49	41.57	52.49	41.57
2016	26.243	12.00	10.60	12.00	10.60	57.53	45.28	57.53	45.28

@@@@

INPUT DATA FOR COST EFFECTIVENESS DETERMINATION
PROGRAM: DLC-0.5 FPC

PSC FORM CE 3.1.A
PAGE 1 OF 2
17-Jun-91

AOD: 20 YR PGM: 35 YR GEN TAX LIFE

I. CONSERVATION PROGRAM OPERATIONAL AND COST DATA

(1) GEN REDUCTION PER CUSTOMER....................	1.60 KW and 110 KWH
(2) PEAK REDUCTION PER CUSTOMER..................	1.90 KW
(3) KWH REDUCTION PER CUSTOMER..................	104.00 KWH
(4) KWH REDUCTION THAT IS ON PEAK..................	100 %
(5) TOTAL PARTICIPATING CUSTOMERS..................	26,243

II. CONSERVATION PROGRAM COST DATA

(1) UTILITY NON RECURRING COST PER CUSTOMER.........................	$128
(2) UTILITY NON-RECURRING COST ESCALATION RATE.........................	4.8 %
(3) UTILITY RECURRING COST PER CUST PER YEAR.........................	$57
(4) UTILITY RECURRING COST ESCALATION RATE.........................	0.5 %
(5) UTILITY REBATE/FINANCIAL INCENTIVE............	$0
(6) CUSTOMER EQUIPMENT COST PER CUST............	$0
(7) CUSTOMER EQUIPMENT ESCALATION RATE............	4.8 %
(8) CUSTOMER O&M COST PER CUST PER YEAR...........	($101.72)
(9) CUSTOMER O&M ESCALATION RATE..................	0.0 %
(10) SOCIETAL COST PER CUST PER YEAR................	$0
(11) SOCIETAL BENEFIT PER CUST PER YEAR............	$0
(12) FEDERAL INCOME TAX CREDIT PER CUST...........	$0

III. UTILITY MARGINAL COST DATA

(1) IN-SERVICE YEAR FOR AVOIDED GEN, TRN, AND DIST FACILITIES......................	1997
(2) AVOIDED GENERATING UNIT ON-PEAK HOURS.........	93 %
(3) CAPACITY FACTOR (C.F).........................	67.27 %
(4) BASE YEAR....................................	1992
(5) AVOIDED FACILITY COST	
A. GEN COST..............................	1036 $/KW
B. TRN COST..............................	21.375 $/KW
C. DIST COST..............................	0 $/KW
ESCALATION RATE.......................	4.5 %
D. GEN FIXED O&M COST.....................	23.82 $/KW YR
ESCALATION RATE.......................	4.75 %
E. TRN FIXED O&M COST........................	0.56 $/KW YR
F. DST FIXED O&M COST........................	0 $/KW YR
ESCALATION RATE..........................	4.8 %
G. AVOIDED GEN UNIT VARIABLE O&M.............	0.0211 C/KWH
ESCALATION RATE..........................	4.8
H. AVOIDED FUEL..............................	2.17202 C/KWH
FUEL ESCALATION RATE.....................	6.204 %
(6) ON-PEAK OFF-SYSTEM SALES AVAILABLE AFTER THE YEAR THE UNIT WAS TO BE ON LINE.........	0 %

IV. UTILITY EMBEDDED COST DATA

(1) FUEL COST..................................	2.394 C/KWH
(2) NON FUEL COST..............................	4.713 C/KWH
(3) KWH ESCALATION RATE............................	2.5894 %

```
#0###
```