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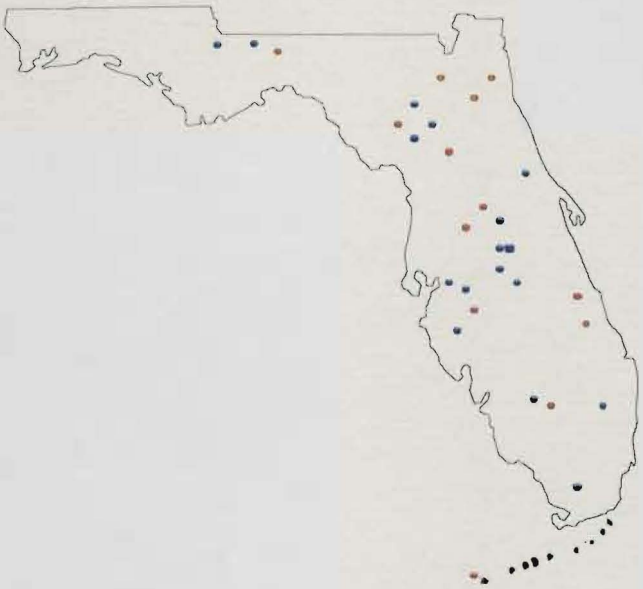
Florida Municipal Power Agency



Ten-Year Site Plan

April 2001

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Florida Municipal Power Agency
Ten Year Power Plant Site Plan
2001-2010

submitted to

Florida Public Service Commission

Orlando, Florida
April 1, 2001

Table of Contents

TABLE OF CONTENTS

List of Tables, Exhibits and Forms

LIST OF TABLES, EXHIBITS, AND FORMS

Section VI Site and Facility Descriptions

Executive Summary

EXECUTIVE SUMMARY

The following information is provided in accordance with Florida Public Service Commission rules 25-22.070, 25-22.071, and 25-22.072 which requires certain electric utilities in the State of Florida to submit a Ten Year Site Plan. The plan is required to describe the estimated electric power generating needs and to identify the general location of any proposed power plant sites.

The Florida Municipal Power Agency is a project-oriented, joint-action agency where each project is, in essence, a separate utility. The aggregate ownership of operational generation facilities for five separate Agency projects at December 31, 2000 was 516 MW of which 254 MW are owned by the All-Requirements Project.

The FMPA generation plans for municipal systems included in this report are as follows:

2001 Cane Island Combined Cycle unit 3	125 MW
2003 Stanton Combined Cycle unit A	63 MW
2005 Fluidized-Bed Petroleum Coke Unit in Lakeland	100 MW

FMPA's direct responsibility for power supply planning can be separated into two parts. For the All-Requirements Project, where the Agency has committed to supply all the power requirements of several cities, the Agency is solely responsible for power supply planning. For member systems which are not in the All-Requirements Project, the Agency's role has been to evaluate joint action opportunities and make the findings available to the membership where each member can elect whether or not to participate. This report presents information on the aggregate of the existing and planned generation for all of the established Agency projects. The specific descriptions of existing and planned facilities include the current status of the aggregate of all the Agency projects. The sections on load forecasts and conservation programs provide information on the All-Requirements Project participants only.

FMPA has added three additional members to the All-Requirements Project in 2000. The City of Ft. Meade joined the Project effective February 1, the Town of Havana joined on July 1, and the City of Newberry joined the All-Requirements Project effective December 1, 2000. FMPA plans to add one additional member, the City of Lake Worth, in 2002. All of the firm power purchases and generating resources owned by Lake Worth will be incorporated into the All-Requirements Project as a purchased capacity-and-energy contract. As is done for its current All-Requirements members, FMPA will collectively plan for and provide all the power requirements (above certain excluded resources) for Lake Worth.

Section I

Description of FMPA

DESCRIPTION OF FMPA

General

The Florida Municipal Power Agency ("FMPA" or "Agency") was created on February 24, 1978, by the signing of the Interlocal Agreement among its 29 members, which agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Organization and Management

Each city commission, utility commission, or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of the Agency. The Board has the responsibility of developing and approving the Agency's budget, hiring a General Manager, and establishing both bylaws which govern how the Agency operates and policies which implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of thirteen representatives elected by the Board plus the current Chairman and Vice Chairman of the Board. The Executive Committee meets regularly to control the Agency's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

Agency Projects

FMPA currently has five power supply projects in operation: (i) the St. Lucie Project; (ii) the Stanton Project; (iii) the Tri-City Project; (iv) the All-Requirements Project and (v) the Stanton II Project.

St. Lucie Project: On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project.

Stanton Project: On August 13, 1984, the Agency purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit No. 1, a coal-fired electric generation unit with a nominally-rated net high dispatch capacity of 428 MW. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project.

Tri-City Project: On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of the Agency's members are participants in the Tri-City Project.

All-Requirements Project: Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for thirteen of its members. In 1997, the cities of Vero Beach and Starke joined the All-Requirements Project. In January 1998, Fort Pierce Utilities Authority became an All-Requirements member. Key West joined the Project in April 1998 and the City of Ft. Meade, the Town

of Havana, and the City of Newberry joined in February, July, and December of 2000. The City of Lake Worth is anticipated to be included in the All-Requirements Project sometime in 2002. The current supply resources of the Project include: (i) the purchase of a 6.5060 percent undivided ownership interest in Stanton Unit No. 1 from OUC; (ii) the purchase from OUC of a 5.1724 percent undivided ownership interest in OUC's Stanton Unit No. 2 (iii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 37 MW combustion turbines (Units A and B) at the OUC Indian River Plant; (iv) capacity and energy from FMPA's 21 percent undivided ownership interest in two 129 MW combustion turbines (Units C and D) at the OUC Indian River Plant; (v) capacity and energy from FMPA's 50 percent undivided ownership interest in a 30 MW combustion turbine (Cane Island Unit 1) and a 120 MW combined cycle (Cane Island Unit 2) at Kissimmee Utility Authority's (KUA) Cane Island Power Park; (vi) capacity and energy from two reconditioned combustion turbines located in the Key West City Electric System (17.5 MW each); (vii) capacity and energy purchases from other utilities including OUC (150 MW), Florida Power & Light Company (120 MW), Florida Power Corporation (40 MW), the City of Lake Worth (10 MW), Gainesville Regional Utilities (43 MW), the City of Lakeland (100 MW), the City of Vero Beach (155 MW), Ft. Pierce Utility Authority (118 MW), Key West City Electric System (50 MW); (vii) necessary transmission arrangements; and (viii) required dispatching services. With the addition of the four cities that joined the All-Requirements Project in 1997 and 1998, the supply resources of the All-Requirements Project include capacity and energy purchases from each of these cities for city-owned generation and/or firm power resources. FMPA will serve capacity and energy requirements of the City of Ft. Meade, via the full-requirements Tampa Electric agreement currently in place. When the Ft. Meade/Tampa Electric agreement terminates, FMPA will serve Ft. Meade from the Project's portfolio of power-supply resources. Similarly, the Town of Havana and the City of Newberry are currently served by full-requirements agreements with Florida Power Corporation. FMPA will assume power supply responsibilities for these two cities when their current agreements expire.

Stanton II Project: On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton Unit No. 2, a coal-fired unit virtually identical to Stanton Unit No. 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project. Table I-1 gives a summary of member participation by project as of April 1, 2001.

Summary of Project Participants
Table I-1

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Chattahoochee					
City of Clewiston	X			X	
City of Ft Meade	X			X	
Ft Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X			X
City of Lakeland Electric & Water					
City of Lake Worth	X	X		P (2002)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt Dora					
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utilities Commission					
City of Quincy					
City of St Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X
City of Wauchula					
City of Williston					

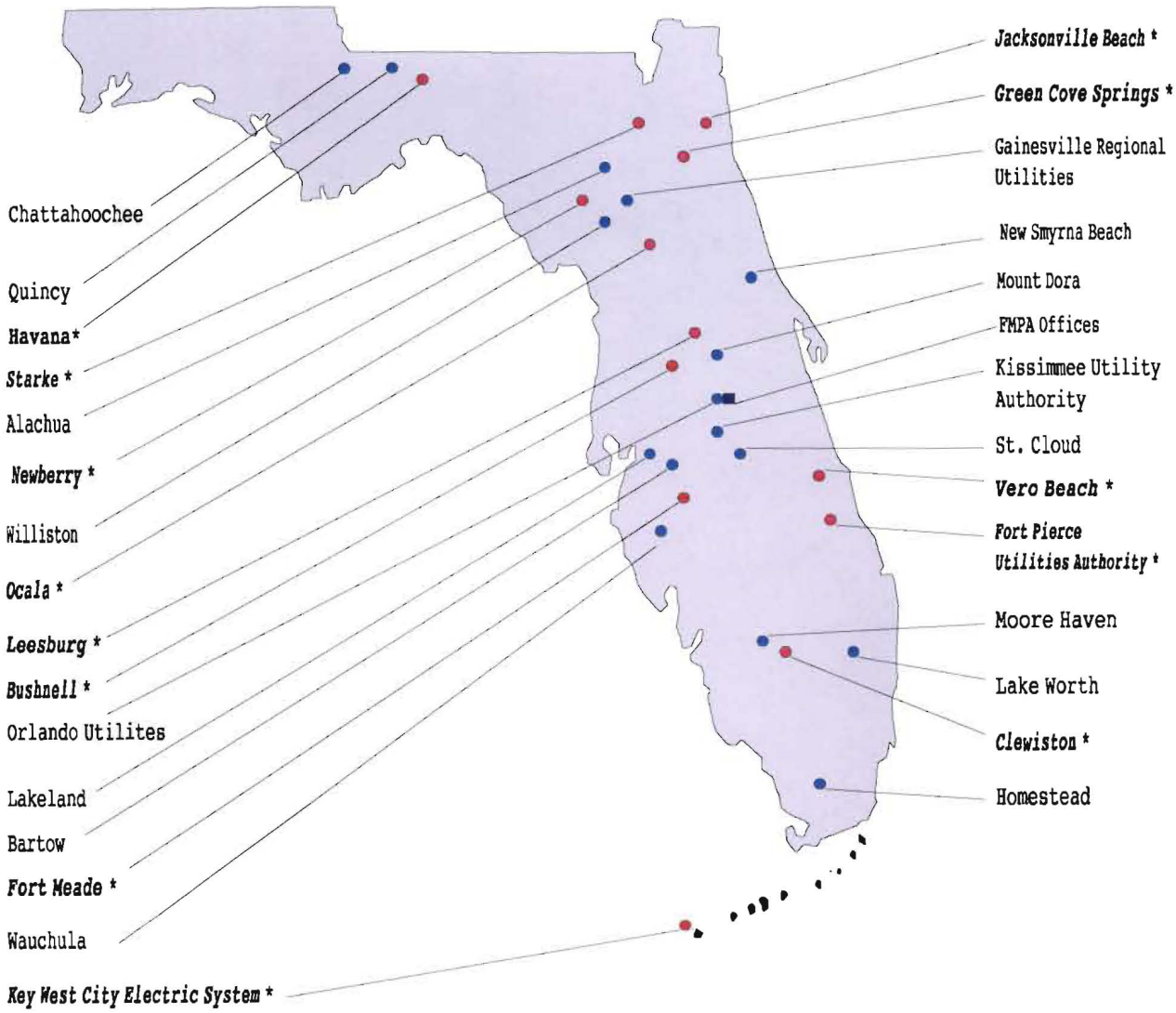
Section II

Description of Existing Facilities

DESCRIPTION OF EXISTING FACILITIES

Section II contains a map showing the location of FMPA members and descriptive data for FMPA generating facilities.

FLORIDA MUNICIPAL POWER AGENCY



** All-Requirements Project Members*

Schedule 1
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Alternate	Fuel Transport Primary	Alternate	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
St. Lucie	2	12-111	NP	UR		TK			8/83	UNK	839,000	74.0	75.0
Stanton Energy Center	1	12-095	BIT	BIT		RR			7/87	UNK	464,580	115.0	115.0
	2	12-095	BIT	BIT		RR			6/96	UNK	464,580	122.0	122.0
Indian River	CT A	12-009	GT	NG	FO2	PL	TK		6/89	UNK	41,400	14.5	18.5
Indian River	CT B	12-009	GT	NG	FO2	PL	TK		7/89	UNK	41,400	14.5	18.5
Indian River	CT C	12-009	GT	NG	FO2	PL	TK		8/92	UNK	112,040	22.0	27.0
Indian River	CT D	12-009	GT	NG	FO2	PL	TK		10/92	UNK	112,040	22.0	27.0
Cane Island	1		GT	NG	FO2	PL	TK		1/95	UNK	40,000	15.2	15.2
Cane Island	2		CC	NG	FO2	PL	TK		6/95	UNK	122,000	54.4	60.2
Stock Island	CT 2		CT	FO2	FO2	TK	TK		6/99	UNK	21,000	17.5	17 5
Stock Island	CT 3		CT	FO2	FO2	TK	TK		6/99	UNK	21,000	17.5	17.5

Section III

Forecast of Demand and Energy for the All-Requirements Power Supply Project

FORECAST OF DEMAND AND ENERGY FOR THE ALL-REQUIREMENTS POWER SUPPLY PROJECT

Introduction

The basis for any determination of additional capacity commitments is the load forecast. This necessitates that great care be exercised when projecting future demand and energy requirements. FMPA is responsible for preparing load and energy projections for each of the All-Requirements Project participants. The forecast process includes existing ARP member cities and identifies future cities that are likely to become Project members. Forecasts are prepared on an individual city basis and then aggregated into projections of FMPA demand and energy requirements.

Compared to more simplistic linear trend forecasting models, statistical models such as those used by FMPA are more costly to implement but allow the analyst greater insight into the factors that actually drive the demand for electricity. The type of forecasting processes used by FMPA strikes an appropriate balance between cost and the level of sophistication required to adequately plan for future power supply requirements. The tools utilized by FMPA allow great flexibility in assessing the impact of numerous driving factors on electric load growth and provide the ability to assess alternative growth scenarios.

Methodology

In preparing forecasts, FMPA analyzes and projects the major driving factors that are related to the demand for electricity by its members. These factors include demographic factors (population and customer growth), weather impacts on loads, economic conditions, conservation programs and significant incremental changes (new cities) which may impact the forecast. FMPA projects energy required for load using recognized modeling techniques and then estimates winter and summer peak demands using load factor analysis.

To estimate All-Requirements Project member energy requirements, several relatively standardized techniques are utilized including:

- Econometric modeling of member customer class requirements
- Aggregate econometric modeling of system requirements
- Statistical Analysis Techniques (Time Series, Multiple Regression, Autoregression, Box Jenkins)
- Incremental load analysis
- Informed Judgement.

In analyzing the relationship between energy requirements and driving variables, FMPA utilizes a commercially available software package to perform statistical analysis and

prepare standardized tests of statistical significance to evaluate alternative forecast models. Once a model is selected, energy forecasts are prepared using the selected model and forecast assumptions for driving variables used by the model (customers, weather, economics, etc.). Forecasted energy is then analyzed for reasonableness, compared to historical patterns and modified as appropriate using informed judgement and appropriate incremental load additions or reductions.

As part of the forecasting process, FMPA evaluates standardized statistical measurements to assess:

- The overall significance of the forecast model
- The statistical significance of individual driving variables
- The relative explanatory performance of the model
- The validation of model structure for complexity and dynamics
- The utilization of these types of tests to permit the development of forecast models which are statisitically valid and appropriate for use in forecasting.

It is important to note that no matter how sophisticated and reliable a model appears to be based upon historical relationships and statistical validation, a model is a simplification of the actual process and cannot capture every nuance of cause and effect relations. Thus, differences between load forecasts and actual realized loads will always be present. Additionally, since we live in a dynamic world that is constantly changing, the occurrence of forecasting error is unavoidable. However, every effort is made to minimize error through the use of sensitivity or uncertainty analysis.

The primary method for dealing with load forecast uncertainty is to prepare alternative forecasts by assuming different scenarios of events that will impact the forecast. FMPA has chosen to capture the potential levels of forecast uncertainty by establishing bandwidths around the base case demand and energy forecasts. This procedure corresponds with statistical theory that indicates that, in absolute terms, the level of forecast uncertainty will increase as the forecast progresses into future years. For example, in 2001 the one-sigma uncertainty range for the FMPA/ARP summer peak load is 174 MW (from high to low). By 2010 the uncertainty range has grown to 501 MW.

Results

FMPA forecasts continued population growth for the service territory based largely on the projected growth in the County population as determined by the University of Florida Bureau of Economic and Business Research, and published in the Florida Statistical Abstract, 2000. Inflation is projected to remain at low levels and the price of electricity is expected to remain constant throughout the forecast period. Normal weather conditions are assumed for this forecast. Final forecast results give the All-Requirements Project an average annual compounded growth of 3.0% (2001 to 2010) for Net Energy for Load and 3.1% for Summer Peak Demand [including Lake Worth (2002), Havana (2003), Newberry (2006) and Ft. Meade (2009)].

Schedule 2.1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					Commercial	
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
1992			857	72,303	11.86	1,000	13,082	76.44
1993			910	73,460	12.39	1,044	13,259	78.71
1994			962	74,817	12.86	1,091	14,179	76.96
1995			1,041	76,070	13.69	1,146	13,766	83.25
1996			1,072	77,423	13.84	1,163	14,141	82.21
1997			1,234	103,507	11.92	1,380	19,723	69.96
1998			1,878	141,969	13.23	1,919	27,302	70.28
1999			1,980	151,969	13.03	2,318	28,789	80.52
2000			2,050	154,244	13.29	2,408	29,370	81.99
2001			2,096	156,433	13.40	2,469	29,951	82.43
2002			2,376	180,489	13.16	2,692	33,491	80.38
2003			2,425	182,719	13.27	2,755	33,986	81.06
2004			2,485	185,946	13.36	2,829	34,708	81.51
2005			2,531	188,040	13.46	2,890	35,182	82.14
2006			2,588	190,979	13.55	2,962	35,792	82.76
2007			2,631	192,888	13.64	3,021	36,242	83.36
2008			2,673	194,716	13.73	3,081	36,682	83.99
2009			2,744	198,796	13.80	3,149	37,337	84.34
2010			2,784	200,479	13.89	3,206	37,752	84.92

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWh	Industrial Average No. of Customers	Average kWh Consumption Per Customer	Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1992					52	7	1,916
1993					48	9	2,011
1994					59	10	2,122
1995					65	11	2,263
1996					76	10	2,321
1997					62	14	2,690
1998					65	15	3,877
1999					69	18	4,385
2000					71	17	4,546
2001					72	17	4,654
2002					78	17	5,163
2003					79	17	5,276
2004					80	17	5,411
2005					82	17	5,520
2006					83	19	5,652
2007					84	19	5,755
2008					85	19	5,858
2009					87	21	6,001
2010					88	21	6,099

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1992		127	2,043		85,385
1993		134	2,145		86,719
1994		66	2,188		88,996
1995		80	2,343		89,836
1996		84	2,405		91,564
1997		160	2,850		123,230
1998		680	4,557		169,271
1999		272	4,657		180,758
2000		288	4,834		183,614
2001		289	4,943		186,384
2002		322	5,485		213,980
2003		347	5,623		216,705
2004		337	5,748		220,654
2005		344	5,864		223,222
2006		352	6,004		226,771
2007		359	6,114		229,130
2008		365	6,223		231,398
2009		376	6,377		236,133
2010		383	6,482		238,231

Schedule 3.1
History and Forecast of Summer Peak Demand
All-Requirements Project - Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
1992	451				----				451
1993	468				----				468
1994	454				----				454
1995	504				----				504
1996	509				----				509
1997	644				----				644
1998	946				----				946
1999	981				----				981
2000	979				----				979
2001	1,032				4.0				1,028
2002	1,140				4.0				1,136
2003	1,172				4.0				1,168
2004	1,198				4.0				1,194
2005	1,222				4.0				1,218
2006	1,252				4.0				1,248
2007	1,276				4.0				1,272
2008	1,299				4.0				1,295
2009	1,333				4.0				1,329
2010	1,355				4.0				1,351

Schedule 3.2
History and Forecast of Winter Peak Demand
All-Requirements Project - Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
1992	426				----				426
1993	410				----				410
1994	442				----				442
1995	503				----				503
1996	553				----				553
1997	499				----				499
1998	686				----				686
1999	927				----				927
2000	953				----				953
2001	983				7.0				976
2002	1,086				7.0				1,079
2003	1,110				7.0				1,103
2004	1,140				7.0				1,133
2005	1,163				7.0				1,156
2006	1,193				7.0				1,186
2007	1,216				7.0				1,209
2008	1,238				7.0				1,231
2009	1,272				7.0				1,265
2010	1,294				7.0				1,287

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1992	2,043						2,043	52%
1993	2,145						2,145	52%
1994	2,188						2,188	55%
1995	2,343						2,343	53%
1996	2,405						2,405	50%
1997	2,845						2,845	50%
1998	4,457						4,457	54%
1999	4,656						4,656	57%
2000	4,834						4,834	58%
2001	4,943						4,943	57%
2002	5,485						5,485	58%
2003	5,623						5,623	58%
2004	5,749						5,749	58%
2005	5,864						5,864	58%
2006	6,003						6,003	57%
2007	6,114						6,114	57%
2008	6,223						6,223	57%
2009	6,378						6,378	57%
2010	6,482						6,482	57%

Schedule 3.1
Forecast of Summer Peak Demand
All-Requirements Project - High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2001	1,134				4.0				1,130
2002	1,263				4.0				1,259
2003	1,321				4.0				1,317
2004	1,373				4.0				1,369
2005	1,421				4.0				1,417
2006	1,475				4.0				1,471
2007	1,523				4.0				1,519
2008	1,569				4.0				1,565
2009	1,628				4.0				1,624
2010	1,672				4.0				1,624

Schedule 3.2
Forecast of Winter Peak Demand
All-Requirements Project - High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2001	1,130				7.0				1,123
2002	1,254				7.0				1,247
2003	1,297				7.0				1,290
2004	1,357				7.0				1,350
2005	1,403				7.0				1,396
2006	1,456				7.0				1,449
2007	1,502				7.0				1,495
2008	1,546				7.0				1,539
2009	1,601				7.0				1,594
2010	1,645				7.0				1,638

Schedule 3.3
Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2001	5,192						5,192	52%
2002	5,851						5,851	53%
2003	6,127						6,127	54%
2004	6,353						6,353	53%
2005	6,698						6,698	54%
2006	6,949						6,949	54%
2007	7,171						7,171	55%
2008	7,389						7,389	55%
2009	7,651						7,651	55%
2010	7,859						7,859	55%

Schedule 3.1
Forecast of Summer Peak Demand
All-Requirements Project - Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2001	960				4.0				956
2002	1,058				4.0				1,054
2003	1,077				4.0				1,073
2004	1,090				4.0				1,086
2005	1,102				4.0				1,098
2006	1,120				4.0				1,116
2007	1,132				4.0				1,128
2008	1,144				4.0				1,140
2009	1,166				4.0				1,162
2010	1,177				4.0				1,162

Schedule 3.2
Forecast of Winter Peak Demand
All-Requirements Project - Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2001	854				7.0				847
2002	947				7.0				940
2003	959				7.0				952
2004	977				7.0				970
2005	989				7.0				982
2006	1,008				7.0				1,001
2007	1,020				7.0				1,013
2008	1,031				7.0				1,024
2009	1,055				7.0				1,048
2010	1,066				7.0				1,059

Schedule 3.3
Forecast of Annual Net Energy for Load - GWh
All-Requirements Project - Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2001	4,749						4,749	63%
2002	5,233						5,233	63%
2003	5,302						5,302	63%
2004	5,378						5,378	63%
2005	5,436						5,436	63%
2006	5,519						5,519	63%
2007	5,575						5,575	62%
2008	5,630						5,630	62%
2009	5,732						5,732	62%
2010	5,784						5,784	62%

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2000		Forecast - 2001		Forecast - 2002	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWh	MW	GWh	MW	GWh
January	953	368	983	377	1,086	416
February	770	326	835	336	916	372
March	681	351	716	362	792	401
April	703	345	753	362	833	401
May	923	443	856	433	948	480
June	908	451	949	461	1,051	512
July	979	482	987	505	1,089	561
August	922	493	1,032	509	1,140	565
September	900	453	937	459	1,038	511
October	843	376	840	408	932	455
November	736	348	723	352	802	391
December	927	397	782	381	857	421

CONSERVATION PROGRAMS

Introduction

FMPA's demand side programs are designed to improve efficiency, implement direct control of residential appliances, encourage time-of-use rates, and achieve additional conservation through commercial and industrial audits.

FMPA's members have promoted their conservation programs by providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. These presentations are given both in person and on video tape. Additionally, bill inserts have been utilized to keep customers aware of available conservation programs. FMPA will continue to expand services as needed to assist members in increasing the promotion and use of conservation programs to retail customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness.

FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

Existing Conservation Programs

FMPA's All-Requirements Participants have offered some or all of the following conservation programs:

1) Residential Energy Audits Program: This Program offers a walk-through audit to identify energy savings opportunities. Energy Star program has been offered since October 1999.

2) High-Pressure Sodium Outdoor Lighting Conversion: This program replaces mercury-vapor street lights with high-pressure sodium lights.

3) Assistance for Commercial/Industrial Audits: Free on-site audits are conducted for all interested customers and recommendations are made for energy efficiency improvements. ESCO referral is also provided upon request.

4) Commercial Time-of-Use Program: Time-of-use rates are offered to commercial and industrial customers with the intention of shifting demand from peak to off-peak periods.

5) Natural Gas Promotion: During Energy Audits, recommend the conversion of old, inefficient electric heat and water heaters to natural gas when the conversion would benefit the customer.

6) Residential Load Management Program: This program has been offered to customers with central electric heating, central air conditioning and electric water heating. The utility is allowed to control some or all of these appliances during periods of peak demand and the customer receives a fixed monthly credit on their bill for each device under control. The following table indicates the amount of summer and winter peak demand reduction and total net energy reduction attributable to this program.

7) Fix-Up Program for the Elderly and Handicapped: Weatherization measures that target low-income housing.

Section V

Forecast of Facilities Requirements

FORECAST OF FACILITIES REQUIREMENTS

For member cities not involved in the All-Requirements Project, the responsibility for planning their future generation and transmission requirements lies ultimately with the individual utility. For the FMPA St. Lucie, Stanton, Stanton II and Tri-City Projects, FMPA has no power supply planning responsibility. However, FMPA periodically reviews the supply plans that might be worthwhile for FMPA or the cities to consider.

FMPA's planning process involves evaluating new generating capacity, along with new purchased power options, if appropriate, and conservation measures that are planned and implemented by the All-Requirements Project participants. The planning process has also included periodic Requests for Proposals in an effort to consider all possible options. FMPA normally performs its generation expansion planning on a least-cost basis considering both new purchased-power options, as well as, options on construction of generating capacity and demand-side resources when cost effective. The generation expansion plan optimizes the planned mix of possible supply-side resources by simulating their dispatch for each year of the study period while considering variables including fixed and variable resource costs, fuel costs, planned maintenance outages, terms of purchase contracts, minimum reserve requirements and options for future resources. FMPA plans on an annual reserve level of approximately 18% of the summer peak, which is in compliance with the reserve margin criteria of the Florida Public Service Commission.

Currently, the Agency on behalf of the All-Requirements Project, is planning to add additional capacity in 2001, 2003 and 2005. With the ability to add generation at the Cane Island Power Park, a portion of the future new capacity will consist of 125 MW from a 250 MW "F" class combined cycle unit later this year. FMPA is actively working with the Kissimmee Utility Authority (KUA) on the construction of the combined cycle unit which is expected to commence commercial operation in June 2001. Currently in negotiation, FMPA is working with OUC, KUA and Southern to procure 63 MW of a 633 MW gas-fired combined cycle unit to be built on OUC's Stanton Energy Center site. The unit is expected to be on line by the fall of 2003. In a joint project with the City of Lakeland, 100 MW from a 288 MW fluidized-bed petroleum coke unit is planned for 2005. FMPA is currently in negotiation with Lakeland officials on this project.

FMPA is continually reviewing its options, seeking joint participation when feasible, and may change the megawatts required, the year of installment, the type of generation, and/or the site as conditions change.

Schedule 5
Fuel Requirements - All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 1999	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear (a)		Trillion BTU			4,325	4,769	5,887	4,785	5,887	4,769	5,887	5,120	5,887	5,103
(2)	Coal		1000 Ton			451	481	481	483	652	771	772	774	772	772
	Residual														
(3)		Steam	1000 BBL												
(4)		CC	1000 BBL												
(5)		CT	1000 BBL												
(6)		TOTAL	1000 BBL			0	0	0	0	0	0	0	0	0	0
	Distillate														
(7)		Steam	1000 BBL												
(8)		CC	1000 BBL												
(9)		CT	1000 BBL			541	127	49	43	66	42	30	17	8	12
(10)		TOTAL	1000 BBL			541	127	49	43	66	42	30	17	8	12
	Natural Gas														
(11)		Steam	1000 MCF			1,458	866	1,657	2,161	1,644	2,452	3,259	4,835	5,329	6,119
(12)		CC	1000 MCF			5,507	6,444	10,368	13,511	12,753	12,242	13,215	15,157	15,330	15,642
(13)		CT	1000 MCF			1,174	1,573	2,134	2,277	1,807	2,358	2,950	3,917	3,981	4,343
(14)		TOTAL	1000 MCF			8,138	8,883	14,159	17,949	16,205	17,052	19,424	23,909	24,640	26,105
(15)	Other (Specify)		Trillion BTU			-----	-----	-----	-----	-----	-----	-----	-----	-----	-----

(a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 6.1
Energy Sources - All-Requirements Project

(1)	(2)	(3)	(4)	(5) Actual	(6) Actual	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		**Units**	1999	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
(1)	**Annual Firm Inter-Region Interchange**		**GWh**			0	0	0	0	0	0	0	0	0	0
(2)	**Nuclear (a)**		**GWh**			402	444	548	445	548	444	548	476	548	475
(3)	**Coal**		**GWh**			1,104	1,179	1,179	1,183	1,597	1,888	1,891	1,897	1,892	1,892
	Residual														
(4)		**Steam**	**GWh**												
(5)		**CC**	**GWh**												
(6)		**CT**	**GWh**												
(7)		**TOTAL**	**GWh**			0	0	0	0	0	0	0	0	0	0
	Distillate														
(8)		**Steam**	**GWh**												
(9)		**CC**	**GWh**												
(10)		**CT**	**GWh**			93	22	9	7	11	7	5	3	1	2
(11)		**TOTAL**	**GWh**			93	22	9	7	11	7	5	3	1	2
	Natural Gas														
(12)		**Steam**	**GWh**			121	72	138	180	137	204	272	403	444	510
(13)		**CC**	**GWh**			787	921	1,481	1,930	1,822	1,749	1,888	2,165	2,190	2,235
(14)		**CT**	**GWh**			78	105	142	152	120	157	197	261	265	290
(15)		**TOTAL**	**GWh**			986	1,098	1,761	2,262	2,079	2,110	2,356	2,829	2,899	3,034
(16)	**NUG**		**GWh**			0	0	0	0	0	0	0	0	0	0
(17)	**HYDRO**		**GWh**			0	0	0	0	0	0	0	0	0	0
(18)	**Interchange**		**GWh**			2,357	2,743	2,126	1,851	1,628	1,555	1,314	1,018	1,038	1,080
(19)	**Net Energy for Load**		**GWh**			4,943	5,485	5,623	5,748	5,864	6,004	6,114	6,224	6,378	6,482

a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 6.2
Energy Sources - All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1999	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Inter-Region Interchange		%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	Nuclear (a)		%			8.1%	8.1%	9.7%	7.7%	9.3%	7.4%	9.0%	7.7%	8.6%	7.3%
(3)	Coal					22.3%	21.5%	21.0%	20.6%	27.2%	31.4%	30.9%	30.5%	29.7%	29.2%
	Residual														
(4)		Steam	%												
(5)		CC	%												
(6)		CT	%												
(7)		TOTAL	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distillate														
(8)		Steam	%												
(9)		CC	%												
(10)		CT	%			1.9%	0.4%	0.2%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%
(11)		TOTAL	%			1.9%	0.4%	0.2%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%
	Natural Gas														
(12)		Steam	%			2.5%	1.3%	2.5%	3.1%	2.3%	3.4%	4.4%	6.5%	7.0%	7.9%
(13)		CC	%			15.9%	16.8%	26.3%	33.6%	31.1%	29.1%	30.9%	34.8%	34.3%	34.5%
(14)		CT	%			1.6%	1.9%	2.5%	2.6%	2.1%	2.6%	3.2%	4.2%	4.2%	4.5%
(15)		TOTAL	%			20.0%	20.0%	31.3%	39.4%	35.5%	35.1%	38.5%	45.5%	45.5%	46.8%
(16)	NUG		%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(17)	Hydro		%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	Other		%			47.7%	50.0%	37.8%	32.2%	27.8%	25.9%	21.5%	16.4%	16.3%	16.7%
(19)	NET ENERGY FOR LOAD		%			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(a) Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.

Schedule 7.1
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (2) MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Availability MW	System Firm Summer Peak Demand MW	Reserve Margin (1) before Maintenance MW	Reserve Margin (1) before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin (1) after Maintenance MW	Reserve Margin (1) after Maintenance % of Peak
2001	498	706	0	0	1,204	1,032	171	16.6%	0	171	16.6%
2002	527	831	0	0	1,358	1,140	234	20.5%	0	234	20.5%
2003	527	846	0	0	1,373	1,172	211	18.0%	0	211	18.0%
2004	590	815	0	0	1,405	1,198	216	18.0%	0	216	18.0%
2005	690	740	0	0	1,430	1,222	220	18.0%	0	220	18.0%
2006	690	782	0	0	1,472	1,252	225	18.0%	0	225	18.0%
2007	690	812	0	0	1,502	1,276	231	18.1%	0	231	18.1%
2008	690	853	0	0	1,543	1,299	234	18.0%	0	234	18.0%
2009	690	891	0	0	1,581	1,333	240	18.0%	0	240	18.0%
2010	690	919	0	0	1,609	1,355	244	18.0%	0	244	18.0%

(1) Reserve Margin includes resrves associated with partial requirements purchases.
(2) Includes nuclear capacity owned directly by some Project participants.

Schedule 7.2
Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Availability	System Firm Winter Peak Demand	Reserve Margin (1) before Maintenance		Scheduled Maintenance	Reserve Margin (1) after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2001	404	811	0	0	1,215	983	219	22.3%	0	219	22.3%
2002	553	772	0	0	1,325	1,086	244	22.5%	0	244	22.5%
2003	553	773	0	0	1,326	1,110	233	21.0%	0	233	21.0%
2004	616	728	0	0	1,344	1,140	219	19.2%	0	219	19.2%
2005	616	732	0	0	1,348	1,163	200	17.2%	0	200	17.2%
2006	716	670	0	0	1,386	1,193	200	16.8%	0	200	16.8%
2007	716	678	0	0	1,394	1,216	182	15.0%	0	182	15.0%
2008	716	714	0	0	1,430	1,238	186	15.0%	0	186	15.0%
2009	716	749	0	0	1,465	1,272	191	15.0%	0	191	15.0%
2010	716	775	0	0	1,491	1,294	193	14.9%	0	193	14.9%
2011	716	808	0	0	1,524	1,315	197	15.0%	0	197	15.0%

(1) Reserve Margin includes resrves associated with partial requirements purchases.
(2) Includes nuclear capacity owned directly by some Project participants.

Section VI

Site and Facility Descriptions

SITE AND FACILITY DESCRIPTIONS

Cane Island Unit 3

The planned Cane Island combined cycle unit will be located at Kissimmee's Cane Island Power Park south and west of the Kissimmee Utility Authority's (KUA) service area.

Environmental Considerations

The environmental impact of the Cane Island #3 unit will be minimal. The combined cycle plant will have emissions controlled to limit the impact on ambient air quality. Dry low NOx technology will be employed via selective catalytic reduction (SCR) for control of nitrogen oxides. The increase in groundwater use should be minimal.

A detailed description of existing environmental conditions at the Cane Island site, along with environmental impacts and mitigation measures is presented in the "Need for Power" and "Site Certification" applications previously submitted for Cane Island #3 to the FPSC by KUA and FMPA. Cane Island Units 1 and 2 are in commercial operation at this site. Unit 1 is a 40 MW (nameplate) simple-cycle combustion turbine. Unit 2 is a 120 MW (nameplate) combined cycle. The site is suitable for approximately 1,000 MW of capacity.

Stanton Combined Cycle Unit A

Stanton A will be located at the existing Stanton Energy Center site located on the eastern side of the service territory of the Orlando Utilities Commission. This plant will utilize a 2x1 combined cycle configuration with two General Electric PG-7231 FA combustion turbines, two heat recovery steam generators, and a steam turbine. The projected output is 633 MW with a heat rate of 7,230 Btu/kWh. Stanton A will be equipped with evaporative inlet cooling, duct firing, and power augmentation to increase output. Natural gas is the primary fuel and number 2 oil will be the backup fuel. The plant will not be equipped with bypass stacks and dampers, but will have the condenser sized such that both combustion turbines can be operated at full load with the steam turbine out of service.

Environmental Considerations

Stanton A is required to comply with the Clean Air Act and current Florida air quality requirements stemming from the Act. One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are NO_x, SO_2, VOC, CO and PM/PM_{10}.

Stanton A is also subject to the New Source Performance Standards (NSPS) requirements for a stationary gas turbine used for electric generation as defined in 40 CFR Part 60, Subpart GG. NSPS Subpart GG places restrictions on emission of NO_x and SO_2 from combustion turbines. NO_x concentrations in the flue gas for combustion turbines with heat inputs greater than 100 MBtu/h are limited to a nominal value of 75 ppmvd (corrected to 15 percent O_2). Upward corrections to NO_x emissions limits are allowed for fuel bound nitrogen content and thermal efficiencies greater than 25 percent.

For further details regarding Stanton A's expected compliance with the Clean Air Act and New Source Performance Standards, please refer to the "Need for Power Application" and "Site Certification" for Stanton A filed earlier this year (2001).

McIntosh Unit 4

The planned McIntosh fluidized-bed unit #4 will be located at the existing McIntosh power plant site in the City of Lakeland's service area. The proposed commercial operating date for this facility is June of 2005.

For purposes of this Ten-Year Site Plan, McIntosh Unit 4 is assumed to be jointly owned (with Lakeland) with an estimated capacity of 288 MW utilizing petroleum coke as the primary fuel and coal as the secondary fuel.

Environmental Considerations

Emissions will be minimized through the use of highly efficient fluidized-bed clean fuel technology. Irrespective of fuel quality or sulfur content, this technology produces very low emissions. This is due to the advantage of burning fuel in a fluidized bed at reduced temperatures. The low burn temperature deters the production of thermal NO_x. Also, a lower excess air level means that NO_x developing from fuel bound nitrogen is lower than for conventional boilers. The fluidized-bed firing temperature encourages the calcium in the sorbent to be extremely reactive and remove up to 99 percent of the sulfur.

Reclaimed water from treated sewage effluent is assumed for supply of the Unit 4 cooling towers. Use of reclaimed water will conserve valuable water resources. It is assumed that cooling tower blowdown will be treated for reuse as part of the design features of Unit 4. Return of wastewater to the City Wastewater Treatment Facility may be possible which would reduce costs but there is limited additional capacity for this alternative. Existing fuel handling and storage facilities will be used, eliminating additional environmental impacts from these facilities.

McIntosh 4 is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. Lakeland's Authority to Construct (ATC) permit for the unit will be obtained through the Site Certification Process. One aspect of

the ATC permit will be the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are SO_2, NO_x, VOC, CO, and PM/PM_{10}. Lakeland and FMPA believe that the inherently low emission profile characteristics of fluidized-bed technology will meet BACT with no additional treatment requirements.

McIntosh Unit 4 is expected to burn 100 percent petroleum coke. The secondary fuel will be the same coal as McIntosh Unit 3 burns. This choice for secondary fuel saves in the cost of an additional fuel storage space. Unit trains will deliver the petroleum coke and coal. The coal is presently delivered by unit train to the site.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Alternate	Fuel Transport Primary	Alternate	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Net Capability Summer MW	Winter MW	Status
Cane Island	3	Osceola Co	CC	NG	FO2	PL	TK		6/01	UNK	250,000	120.0	125.0	V
Stanton	A	Orange Co	CC	NG	FO2	PL			10/03	UNK	633,000	63.0	63.0	P
MacIntosh	4	Polk Co.	CC	PC	Coal	RR	TK		6/05	UNK	288,000	100.0	100.0	P

Schedule 9.1

Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Cane Island Unit 3
(2)	**Capacity**	
	a. Summer:	244 MW (FMPA share is 50%)
	b. Winter:	262 MW (FMPA share is 50%)
(3)	**Technology Type:**	Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	10-01-99
	b. Commercial in-service date:	6-01-01
(5)	**Fuel**	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 oil
(6)	**Air Pollution Control Strategy:**	Dry NOx
(7)	**Cooling Method:**	Mechanical Cooling Towers
(8)	**Total Site Area:**	1,024 acres
(9)	**Construction Status:**	Under construction
(10)	**Certification Status:**	Application approved by FPSC
(11)	**Status with Federal Agencies:**	------
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	4.3%
	Forced Outage Factor (FOF):	4.1%
	Equivalent Availability Factor (EAF):	91.8%
	Resulting Capacity Factor:	------
	Average Net Operating Heat Rate (ANOHR):	6,815 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	30
	Total Installed Cost (In-service year $/kW):	449
	Direct Construction Cost ($/kW):	320
	AFUDC Amount ($/kW):	21
	Escalation ($/kW):	---
	Fixed O&M ($kW-Yr):	2.27
	Variable O&M ($/MWh):	2.82

Schedule 9.2

Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	Stanton CC Unit A
(2)	**Capacity**	
	a. Summer:	633 MW (FMPA share is 63 MW)
	b. Winter:	633 MW (FMPA share is 63 MW)
(3)	**Technology Type:**	Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	9-01-01
	b. Commercial in-service date:	10-01-03
(5)	**Fuel**	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 oil
(6)	**Air Pollution Control Strategy:**	SCR
(7)	**Cooling Method:**	Mechanical Cooling Towers
(8)	**Total Site Area:**	1,100 acres
(9)	**Construction Status:**	Planned
(10)	**Certification Status:**	Certificate of Need filed
(11)	**Status with Federal Agencies:**	------
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	4.0%
	Forced Outage Factor (FOF):	4.0%
	Equivalent Availability Factor (EAF):	92.0%
	Resulting Capacity Factor:	------
	Average Net Operating Heat Rate (ANOHR):	7,363 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	25
	Total Installed Cost (In-service year $/kW):	452
	Direct Construction Cost ($/kW):	463
	AFUDC Amount ($/kW):	31
	Escalation ($/kW):	40
	Fixed O&M ($kW-Yr):	5.32
	Variable O&M ($/MWh):	3.68

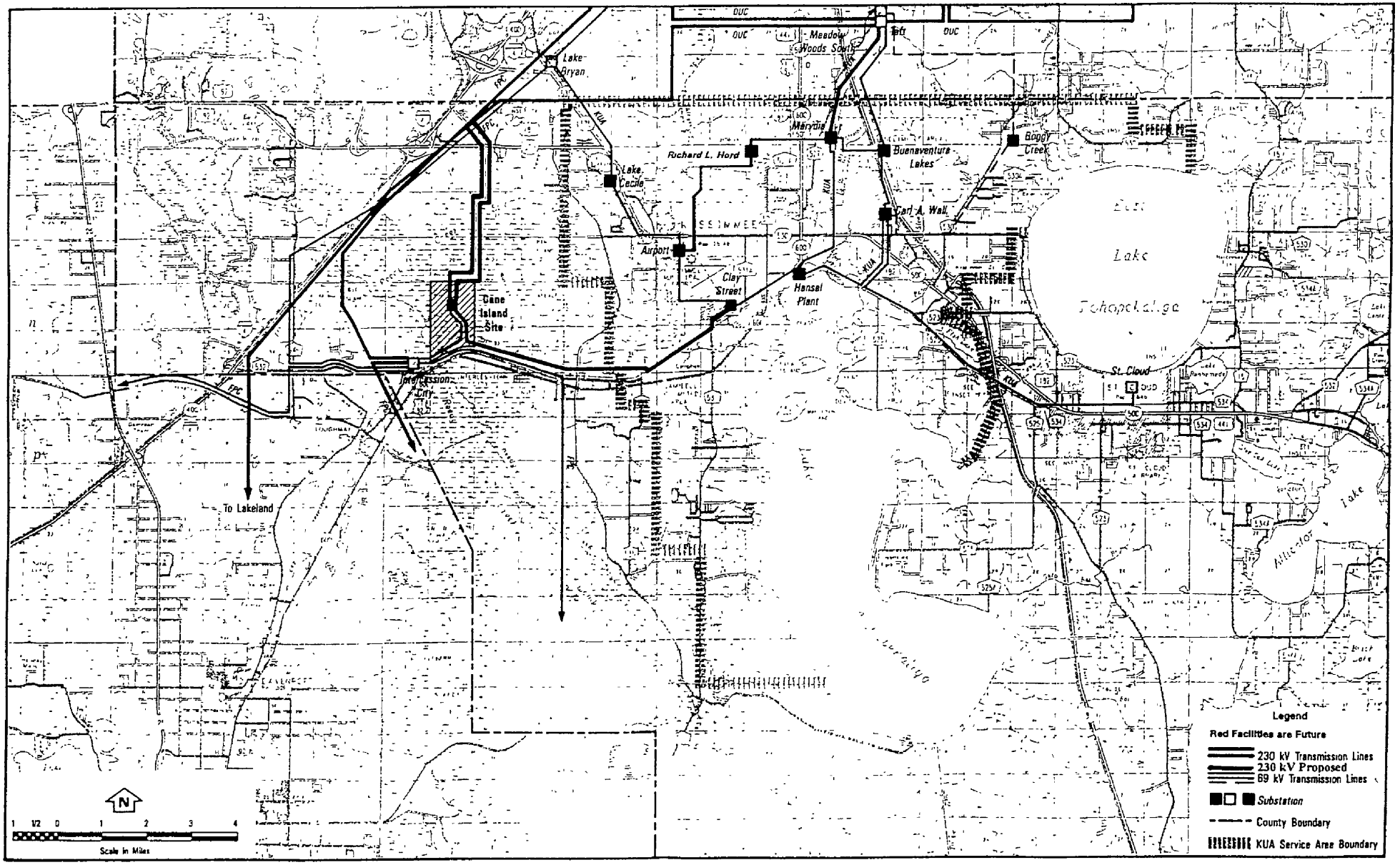
Schedule 9.3

Status Report and Specifications of Proposed Generating Facilities - All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number:**	McIntosh Unit 4
(2)	**Capacity**	
	a. Summer:	288 MW (FMPA share is 100 MW)
	b. Winter:	288 MW (FMPA share is 100 MW)
(3)	**Technology Type:**	Fluidized Bed Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	06-01-02
	b. Commercial in-service date:	06-01-05
(5)	**Fuel**	
	a. Primary fuel:	Petroleum Coke
	b. Alternate fuel:	Coal
(6)	**Air Pollution Control Strategy:**	SNCR, limestone, fabric filters or electrostatic precipitators for particulates
(7)	**Cooling Method:**	Cooling Tower
(8)	**Total Site Area:**	513 acres
(9)	**Construction Status:**	Planned
(10)	**Certification Status:**	------
(11)	**Status with Federal Agencies:**	------
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	7.67%
	Forced Outage Factor (FOF):	12.0%
	Equivalent Availability Factor (EAF):	81.0%
	Resulting Capacity Factor:	81.00%
	Average Net Operating Heat Rate (ANOHR):	8,452 BTU/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	30
	Total Installed Cost (In-service year $/kW):	1,617
	Direct Construction Cost ($/kW):	1,317
	AFUDC Amount ($/kW):	135
	Escalation ($/kW):	165
	Fixed O&M ($kW-Yr):	20.76
	Variable O&M ($/MWh):	4.53 (includes limestone)

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines
All-Requirements Project

(1)	**Point of Origin and Termination:**	Cane Island Plant to Intercession City Plant (FPC)
(2)	**Number of Lines:**	one
(3)	**Right-of-Way:**	see map
(4)	**Line Length:**	3.0 miles
(5)	**Voltage:**	230 kV
(6)	**Anticipated Construction Timing:**	begin const 6/2000
(7)	**Anticipated Capital Investment:**	$6 million including substation work
(8)	**Substations:**	see above
(9)	**Participation with Other Utilities:**	KUA


Lake Bryan
Meadow Woods South
Richard L. Hord
Buenaventura Lakes
Boggy Creek
Lake Cecile
Carl A. Wall
Airport
Clay Street
Hansel Plant
Cane Island Site
Intercession City
To Lakeland
Lake Tohopekaliga
St. Cloud
Alligator Lake
Legend
Red Facilities are Future
230 kV Transmission Lines
230 kV Proposed
69 kV Transmission Lines
Substation
County Boundary
KUA Service Area Boundary
N
1 1/2 0 1 2 3 4
Scale in Miles

Appendix I

Transmission Additions

The table on the following page contains a list of planned and proposed transmission line additions for member cities of the Florida Municipal Power Agency who participate in the All-Requirements Project as well as other (non-ARP) member cities who are not required to file a Ten-Year Site Plan. In view of current efforts to form the new Florida RTO Grid Florida, it was considered necessary to document these plans in the public record.

Planned and Proposed Transmission Additions for FMPA Members

City	From	To	Voltage	Estimated In-Service Date
Clewiston	Mc Carthy	Clewiston	138 kV	June 1, 2001
Ft. Pierce	King	Garden City	138 kV	January 1, 2002
	King	Garden City	69 kV	January 1, 2002
Homestead	Redland	Davis Tap	138 kV	December 1, 2002
	Redland	Fla City Tap	138 kV	December 1, 2002
Jacksonville Beach	Ft. Diego	Guano	138 kV	November 1, 2002
	Guano	Sampson	138 kV	November 1, 2002
Key West	Tavernier	Islamorada	138 kV	January 1, 2008
	Islamorada	Marathon	138 kV	January 1, 2008
	Florida City	Tavernier	138 kV	January 1, 2013
Ocala	Blichton	Airport	69 kV	December 1, 2001
	Blichton	Richmond	69 kV	December 1, 2001
	Nuby's Corner	Silver Springs	69 kV	December 1, 2002
	Nuby's Corner	Baseline Rd	69 kV	December 1, 2002
	Red Oak	Silver Springs	230 kV	December 1, 2003
	Ocala Springs	Ergle	69 kV	December 1, 2006
	Ocala Springs	Silver Springs	69 kV	December 1, 2006
	Baseline Rd	Dearmin	69 kV	December 1, 2008
	Fore Corners	Ergle Tap	69 kV	December 1, 2009
	Fore Corners	North	69 kV	December 1, 2009