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FMPA
Florida Municipal Power Agency

Robert C. Williams
Director of Engineering

VIA FEDERAL EXPRESS

April 1, 2004

Ms. Blanca Bayo
Florida Public Service Commission
Bureau of Electric Reliability
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

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COMMISSION
CLERK

Dear Ms. Bayo,

Enclosed are 25 copies of Florida Municipal Power Agency's April 2004 Ten-Year Site Plan.

The Ten-Year Site Plan information is provided in accordance with Florida Public Service Commission rules 25-22.070, 25-22.071, and 25-22.072, which require 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 near-term power plant sites as of 12/31/2003.

If you should have any questions, please feel free to contact either Rick Casey or me.

Sincerely,

Rick Casey for

Robert C. Williams
Director of Engineering

Enclosures

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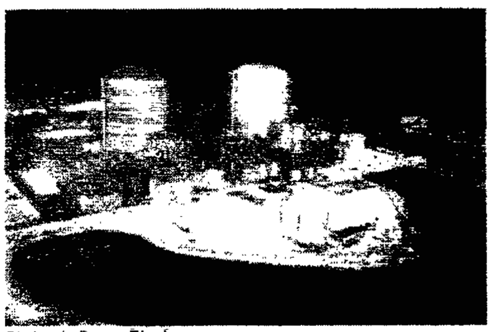
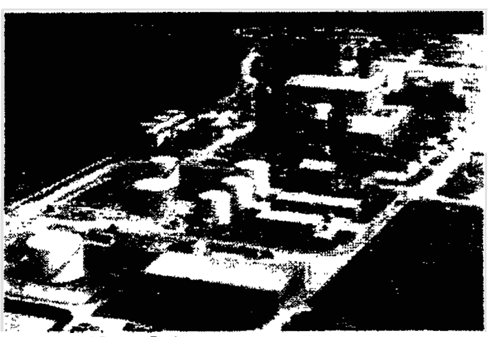
Florida Municipal Power Agency

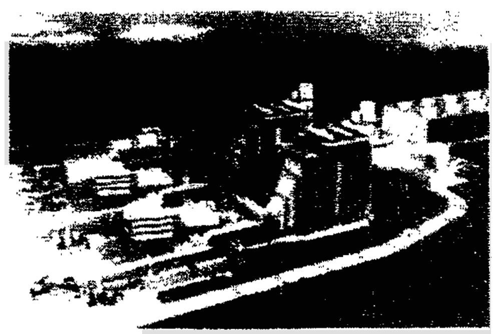
Ten-Year Site Plan

April 2004


St. Lucie Power Plant


Stanton Energy Center


Cane Island Power Park


Stanton Unit A

Community Power + Statewide Strength

Florida Municipal Power Agency

Ten-Year Site Plan 2004-2013

Submitted to

Florida Public Service Commission

April 1, 2004

Community Power + Statewide Strength

Florida Municipal Power Agency

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List of Tables, Exhibits, and Forms

Executive Summary

Community Power + Statewide Strength

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 require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan. The Ten-Year Site Plan is required to describe the estimated electric power generating needs and to identify the general location and type of any proposed near-term generation capacity additions.

The Florida Municipal Power Agency (FMPA) is a project-oriented, joint-action agency. FMPA's direct responsibility for power supply planning can be separated into two parts. First, for the All-Requirements Project (ARP), where the Agency has committed to supplying all of the power requirements of fifteen cities, the Agency is solely responsible for power supply planning. Second, for member systems that are not in the ARP, 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 existing Agency projects and planning information for the ARP.

The ARP winter and summer capacity including owned generation and purchase power for the year 2004 is 1,756 MW and 1,701 MW, respectively. In October, 2003, Stanton Energy Center A began commercial operation, providing FMPA with 127 MW of capacity. This includes the capacity allocated to Kissimmee Utility Authority pursuant to the applicable Stanton Energy Center A joint-ownership and purchase power agreements.

Future ARP generation construction plans for serving its municipal systems included in this report are presented in Table ES-1. Worthy of note is FMPA's awareness of the potential benefits of increased fuel diversity among its generating portfolio, which has prompted FMPA to consider a solid-fuel capacity addition. Due to permitting and scheduling constraints, commercial operation of such a unit, if ultimately decided upon, would not be feasible until the summer of 2010 at the earliest. Nonetheless, consideration and further study of the potential benefits related to construction of a new solid-fueled unit are appropriate from FMPA's perspective.

The most recent member city additions to the ARP occurred in 2002, when Kissimmee Utility Authority and Lake Worth Utilities joined, bringing the total ARP membership to fifteen members. All of the firm power purchases and generating resources owned and purchased by Kissimmee Utility Authority and Lake Worth Utilities have been incorporated into the ARP as purchased capacity-and-energy contracts. As is done for all ARP members, FMPA will collectively plan for and provide all of the power requirements (above certain excluded resources) for Kissimmee Utility Authority and Lake Worth Utilities.

Table ES-1.
FMPA Generation Construction Plans

Unit Description	Commercial Operation (MM/YY)	Summer Capacity (MW)	Winter Capacity (MW)
Stock Island CT4	06/06	22	22
Cane Island CT	01/08	140	175
H.D. King CT	06/08	84	97
Tom G. Smith CT	06/08	84	97
Cane Island CT	06/10	140	175
Municipal Plant CT	06/11	84	97
Stock Island CT5	06/12	22	22
H.D. King CT	06/13	84	97

Section 1.0

Description of FMPA

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1.0 DESCRIPTION OF FMPA

The Florida Municipal Power Agency was created on February 24, 1978, by the signing of the Interlocal Agreement among its 29 members, which 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.

1.1 Organization and Governance

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 FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager, and establishing bylaws that govern how FMPA operates and policies that 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, including nine elected by the Board plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer. The Executive Committee meets regularly to control FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

1.2 FMPA 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 Stanton II Project; and (v) the All-Requirements Project (ARP). Table 1-1, presented at the end of this section, gives a summary of ARP member participation by Project as of April 1, 2004.

1.2.1 St. Lucie Project.

On May 12, 1983, FMPA purchased from Florida Power & Light Company (FPL) an undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit. 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 FMPA's members are participants in the St. Lucie Project. Eleven of these members are also participants in the All-Requirements Project. A reliability exchange results in half of the capacity coming from St. Lucie Unit No. 1 and half coming from St. Lucie No. 2.

1.2.2 Stanton Project.

On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) an undivided ownership interest in Stanton Unit No. 1, a coal-fired electric generation unit. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of FMPA's members are participants in the Stanton Project. Five of these members are also participants in the ARP.

1.2.3 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 undivided ownership interest in Stanton Unit No. 1. Three of FMPA's members are participants in the Tri-City Project and two of those members are also participants in the ARP.

1.2.4 Stanton II Project.

On June 6, 1991, FMPA, under the Stanton II Project structure, purchased from OUC an 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 FMPA's members are participants in the Stanton II Project and five of these members are also participants in the ARP.

1.2.5 All-Requirements Project.

Under the All-Requirements Project (ARP), FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light or Florida Power Corporation (now Progress Energy Florida). As time went on other FMPA members joined the ARP. These members were both non-generating and generating members. The latest members to join the ARP were Kissimmee Utility Authority and Lake Worth, which joined in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in Progress Energy Florida's Crystal River Unit 3. Likewise, a number of ARP members participate in the St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of the capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are, however, considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the Stanton, Tri-City, and Stanton II projects.

The third category of resources is member generation. Capacity included in this category is generation owned by the ARP members either solely or jointly. The ARP purchases this capacity from the ARP members and then commits and dispatches the generation to meet the total requirements of the ARP.

The fourth category of resources is purchase power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members, which were entered into prior to the member joining the ARP.

The ARP also serves the 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 City of Newberry is currently served by full-requirements agreements with Progress Energy Florida. FMPA will assume power supply responsibilities when Newberry's current agreement expires. For planning purposes, the loads for Ft. Meade and Newberry are not included in the ARP loads until the full requirements contracts expire. Likewise, for planning purposes, the full requirements contracts are not considered as resources for the ARP.

Table 1-1.
Summary of Project Participants

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	X
City of Lakeland Electric & Water					
City of Lake Worth	X	X		X	
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 2.0

Description of Existing Facilities

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2.0 DESCRIPTION OF EXISTING FACILITIES

The following section presents a map (Figure 2-1) illustrating the location of FMPA's members as well as tables presenting detailed descriptions of existing ARP generating resources (Table 2-1) and purchase power resources (Table 2-2).

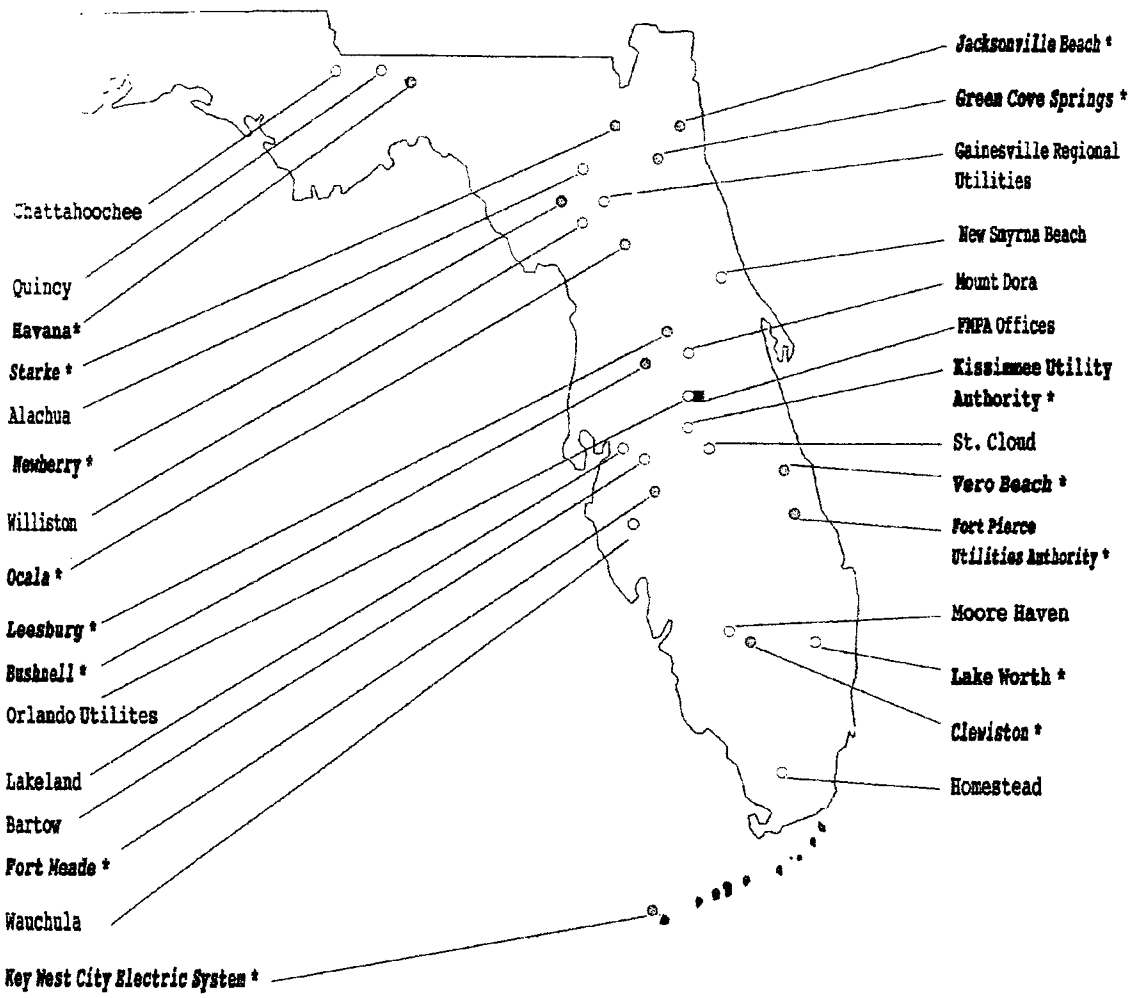

Figure 2-1. Location of FMPA Member Cities

Table 2-1.
ARP Existing Generating Resources (as of December 31, 2003)

Plant Name	Unit No.	Location	Unit Type	Fuel Type Primary	Fuel Type Alternate	Fuel Transportation Primary	Fuel Transportation Alternate	Commercial In-Service MM/YY	Expected Retirement Mo/Yr	Gen. Max Nameplate MW	Net Capability[1] Summer (MW)	Net Capability[1] Winter (MW)
Nuclear Capacity												
Crystal River	3	Citrus	NP	UR	-	TK	-	03/77	UNK	891	24	24
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	UNK	839	61	61
										Total Nuclear Capacity	84	84
Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	(2)	RR	-	07/87	UNK	465	122	122
Stanton Energy Center	2	Orange	ST	BIT	(2)	RR	-	06/96	UNK	465	98	98
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	UNK	671	22	22
Indian River	CT A	Brevard	CT	NG	FO2	PL	TK	06/89	UNK	41	14	19
Indian River	CT B	Brevard	CT	NG	FO2	PL	TK	07/89	UNK	41	14	19
Indian River	CT C	Brevard	CT	NG	FO2	PL	TK	08/92	UNK	112	23	27
Indian River	CT D	Brevard	CT	NG	FO2	PL	TK	10/92	UNK	112	23	27
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	01/95	UNK	40	15	20
Cane Island	2	Osceola	CC	NG	FO2	PL	TK	06/95	UNK	122	54	60
Cane Island	3	Osceola	CC	NG	FO2	PL	TK	01/02	UNK	280	120	125
Stock Island	CT 2	Monroe	CT	FO2	-	WA	-	06/99	UNK	21	18	18
Stock Island	CT 3	Monroe	CT	FO2	-	WA	-	06/99	UNK	21	18	18
										Total Owned Generation	541	575

(1) Totals may not add due to rounding.
(2) Stanton Units 1 and 2 have the ability to supplement primary fuel with landfill methane gas on an as-available basis.

Table 2-1. (continued)
ARP Existing Generating Resources (as of December 31, 2003)

				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	Mo/Yr	MW	Summer (MW)	Winter (MW)
Member Generation												
Vero Beach												
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	UNK	13	13	13
Municipal Plant	2	Indian River	CA	NG	RFO	PL	TK	8/64	UNK	13	13	13
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	9/71	UNK	33	33	33
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	8/76	UNK	56	56	56
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	UNK	40	35	40
Total Vero Beach											150	155
Fort Pierce Utilities Authority												
H.D. King	5	St. Lucie	CA	WH	-	-	-	1/53	UNK	8	8	8
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	1/64	UNK	32	32	32
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	5/76	UNK	50	50	50
H.D. King	9	St. Lucie	CT	NG	FO2	PL	TK	5/90	UNK	23	23	23
H.D. King	D1	St. Lucie	IC	FO2	-	TK	-	4/70	UNK	3	3	3
H.D. King	D2	St. Lucie	IC	FO2	-	TK	-	4/70	UNK	3	3	3
Total Fort Pierce Utilities Authority											118	118
Kissimmee Utility Authority												
Hansel Plant	8	Osceola	IC	NG	FO2	PL	TK	02/59	UNK	2	2	2
Hansel Plant	14	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	15	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	16	Osceola	IC	NG	FO2	PL	TK	02.72	UNK	2	2	2
Hansel Plant	17	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	18	Osceola	IC	NG	FO2	PL	TK	02/72	UNK	2	2	2
Hansel Plant	19	Osceola	IC	FO2	-	TK	-	02/83	UNK	2	2	2
Hansel Plant	20	Osceola	IC	FO2	-	TK	-	02/83	UNK	3	2	3
Hansel Plant	21	Osceola	CT	NG	FO2	PL	TK	02/83	UNK	38	30	38
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	UNK	8	8	6
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	UNK	8	8	6

(1) Totals may not add due to rounding.

Table 2-1. (continued) ARP Existing Generating Resources (as of December 31, 2003)												
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	Mo/Yr	MW	Summer (MW)	Winter (MW)
Member Generation (continued)												
Kissimmee Utility Authority (continued)												
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	UNK	40	15	20
Cane Island	2	Osceola	CC	NG	FO2	PL	TK	6/95	UNK	122	54	60
Cane Island	3	Osceola	CC	NG	FO2	PL	TK	1/02	UNK	280	120	125
Stanton	A	Orange	CC	NG	FO2	PL	TK	10/03	UNK	671	22	22
Indian River	A	Brevard	CT	NG	FO2	PL	TK	6/89	UNK	41	5	6
Indian River	B	Brevard	CT	NG	FO2	PL	TK	6/89	UNK	41	5	6
Total Kissimmee Utility Authority											283	306
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	FO2	-	TK	-	12/76	UNK	31	26	31
Tom G. Smith	GT-2	Palm Beach	CT	NG	FO2	PL	TK	3/78	UNK	20	21	23
Tom G. Smith	MU1	Palm Beach	IC	FO2	-	TK	-	12/65	UNK	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	FO2	-	TK	-	12/65	UNK	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	FO2	-	TK	-	12/65	UNK	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	FO2	-	TK	-	12/65	UNK	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	FO2	-	TK	-	12/65	UNK	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	UNK	27	22	24
Tom G. Smith	S-5	Palm Beach	CA	WA	-	-	-	3/78	UNK	10	9	9
Total Lake Worth											88	97

(1) Totals may not add due to rounding.

Table 2-1. (continued)
ARP Existing Generating Resources (as of December 31, 2003)

				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	Mo/Yr	MW	Summer (MW)	Winter (MW)
Member Generation (continued)												
Keys Energy Services												
Big Pine Key Peaker	1	Monroe	IC	FO2	-	TK	-	2/69	UNK	3	3	3
Cudjoe Key Peaker	2	Monroe	IC	FO2	-	TK	-	8/68	UNK	3	3	3
Cudjoe Key Peaker	3	Monroe	IC	FO2	-	TK	-	8/68	UNK	2	2	2
Stock Island	GT1	Monroe	GT	FO2	-	WA	-	11/78	UNK	20	20	20
Stock Island HSD	IC1	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island HSD	IC2	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island HSD	IC3	Monroe	IC	FO2	-	WA	-	1/65	UNK	2	2	2
Stock Island MSD	MSD1	Monroe	IC	FO2	-	WA	-	6/91	UNK	9	9	9
Stock Island MSD	MSD2	Monroe	IC	FO2	-	WA	-	6/91	UNK	9	9	9
Total Keys Energy Services											50	50
Total Member Generation											689	726
Total Generation Resources											1,311	1,366

(1) Totals may not add due to rounding.

Table 2-2. ARP Purchase Power (as of December 31, 2003)		
Purchase	Summer (MW)	Winter (MW)
Starke (GRU)	3	3
OUC Indian River	87	87
Stanton A	82	82
Progress Energy Florida PR	40	40
FPL Long Term	45	45
Lakeland	100	100
FPL	75	75
OUC C&E	20	20
KUA	20	20
Total	472	472

Florida Municipal Power Agency

Section 3.0

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

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

R. W. Beck, Inc. (Beck) was retained by FMPA to prepare a forecast of peak load and net energy for load for its All-Requirements Project (ARP). The forecast of load and energy requirements is a critical input to many utility processes including, but not limited to, generation expansion planning, fuel and purchased power budgeting, transmission planning, financial planning and budgeting, and staffing. In addition, the load and energy forecast is submitted to the Florida Public Service Commission as part of the Ten-Year Site Plan. Consequently, a rigorous and detailed process which relies on recognized standards of practice, as well as a thorough review of results by various parties, is essential to FMPA operations and long-term planning.

The load and energy forecast has been prepared for a 20 year period, beginning fiscal year 2004 and extending through 2023. The forecast has been prepared on a monthly basis using municipal utility data provided to FMPA by the ARP members and load data maintained by FMPA. Historical and projected economic and demographic data was provided by Economy.com, a nationally-recognized provider of such data. Beck has also relied on ARP members and staff for information and expert judgment regarding local economic and demographic issues specific to each member.

The results of the forecast show that the calendar year net energy for load supplied from the ARP is expected to grow at an annual average growth rate of 2.4 percent from 2004-2013, and then 2.2 percent through 2023. On a normal weather basis, the projected fiscal year 2004 net energy for load and coincident peak supplied from the ARP are 6,952 GWh and 1,392 MW, respectively.

In addition to the base case forecast, Beck prepared a high and low case forecast of winter and summer peak load and net energy for load for planning purposes. The resulting high case annual peak load is 1,474 MW, and the associated net energy for load is 7,361 GWh. The low case annual peak and net energy for load are 1,310 MW and 6,546 GWh, respectively. The high and low cases do not reflect different projections of future conditions with respect to the explanatory variables. Rather, the high and low cases represent a band of uncertainty within which, in the near term, the annual peak and net energy for load are likely to fall under a single set of assumptions about the future.

The following section details the methodology, process, and results of the 2004 ARP forecast. Included in this section is an overview of the methodology that supports the forecast. Following this overview is a brief description of the econometric models used and some of the key explanatory variables. This is followed by a discussion of principal considerations and assumptions relied on for the ARP forecast. Conclusions and recommendations have been included to set the results in their proper context, as well as to identify certain elements within the forecasting process, which may be improved.

3.1 Overview of Methodology

The prediction of energy consumption is impossible without *a priori* knowledge. Because FMPA does not have perfect knowledge about future ARP member consumption of energy, FMPA relies on a forecasting process that balances complex mathematical models with sound judgment and, to the extent available, local, expert knowledge.

In order to predict energy requirements, utilities need a forecasting methodology which explains variations in energy requirements. In addition, understanding relationships which affect energy consumption allows utilities to perform "what-if" analyses, thereby improving decisions. For this reason, electric utilities typically rely on econometric forecasting techniques. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. These historical relationships are evaluated, and then selected on the merits of their statistical ability to explain variation in energy consumption. This ability is often referred to as "goodness-of-fit." These historical relationships are generally assumed to continue into the future, barring any specific information to the contrary. A projection of the explanatory variables is then combined with these relationships to produce a forecast of the dependent variables in question.

3.2 Model Specification

The following discussion summarizes the development of econometric models used to forecast load, energy sales, and customer accounts on a monthly basis. This overview will present a common basis upon which each classification of models was prepared.

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable, and the customer forecast is generated for reporting purposes and to check the sensibility of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers; (ii) real personal income per household; (iii) real electricity prices; and (iv) weather variables. The number of residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the members and the number of households in the member's county.

For the general service class models, the econometric models reflect that energy requirements are best explained by: (i) real retail sales, total personal income, or GDP as a measure of economic activity and population in and around the member's service territory, (ii) the real price of electricity, and (iii) weather variables. In the case of the general service non-demand class, retail sales was typically selected as the long-term driving variable either because it performed better by certain measures, or because the resulting forecast was more sensible. Similarly, for the general service demand class, total personal income was typically selected. For the industrial class, GDP was the typical long-term driving variable, except in cases where the forecast was based on an assumption (e.g., Clewiston and Key West).

Weather variables include heating and cooling degree days for the current month and for the prior month. Lagged degree day variables are included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month. The regression models developed in the prior forecast did not include lagged weather variables, and the model statistics, and possibly the parameters, suffered as a result.

3.3 Projection of NEL and Peak Demand

The forecast of sales for each rate classification described above are summed to equal the total sales of each ARP member. An assumed loss factor, typically based on a five-year average of historical loss factors, is then applied to the total sales to derive monthly NEL.

Projections of summer and winter non-coincident peak demand were developed by applying projected annual load factors to the forecasted net energy for energy on a total ARP member system basis. The projected load factors are generally based on the average relationship between annual NEL and the seasonal peak demand over the period 1999-2003 (i.e., a five-year average). Monthly peak demand is based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids distortion of the averages due to randomness as to the months in which peak weather conditions occurred within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflects that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the member groups, and the transmission providers were derived from monthly coincidence factors averaged generally over the same five-year period (1999-2003). The historical coincidence factors are based on historical coincident peak demand data that is maintained by FMPA, supplemented with hourly load data that was analyzed to identify the demand values at the time of the various peaks. Similarly, the timing of the ARP and member group peaks were determined from an appropriate summation of the hourly load data.

3.4 Principal Considerations and Assumptions

3.4.1 Historical Member Data.

FMPA staff provided historical data for each ARP member. In addition, FMPA staff provided work papers and documentation for the 2003 Load and Energy Forecast. Data provided by FMPA staff included historical customers and sales by rate classification for each of the ARP members. Revenue data was also provided; however, for part of the forecast horizon, only total revenues were available. Data was provided from January, 1992, or the year a new member joined ARP through at least June, 2003, and, in many cases, the end of fiscal year 2003 (i.e. September, 2003).

3.4.2 Weather Data.

Historical weather data has been provided by the National Climatic Data Center (a subsidiary of the National Oceanic and Atmospheric Administration) generally to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was provided, were selected by their quality first, and second by their proximity to the Member. In most cases, the closest first-order weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data. In two cases (Jacksonville Beach and Vero Beach), however, weather from cooperative weather stations, which were closer than the closest first-order station, appeared to be more reflective of select ARP member conditions, based on statistical measures, than the closest first-order weather station.

The influence on electricity sales of weather has been represented through the use of two data series: heating and cooling degree days (HDD and CDD, respectively.) Degree days are derived by comparing the average daily temperature and (in the case of this forecast) 65 °F. To the extent that the average daily temperature exceeds 65 °F, the difference is the number of CDD required to cool the average daily temperature to 65 °F. Conversely, HDD is the result of average daily temperatures which are below 65 °F.

Because predicting future long-term weather patterns is impossible, normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions over the 1971-2000 period.

3.4.3 Economic Data.

Economy.com, a nationally recognized provider, provided both historical and projected economic and demographic data. The data relied on included economic and demographic data for each of the 15 counties in which each ARP member's service territory resides. These data include county population, households, employment, personal income, retail sales, and gross domestic product. Although all data was not necessarily utilized in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales. Note that personal income refers to the total income earned by the population in a county rather than average personal income per capita.

3.4.4 Real Electricity Price Data.

The real price of electricity is derived from a twelve month moving average of real average revenue, based on data provided by FMPA staff (discussed above). To the extent average revenue data specific to a certain rate classification was unavailable (generally January, 1992, through October, 1996), it was assumed to follow the trend of total average revenue of the utility. While a longer lag is typically expected, particularly in the case of residential electricity use, the lack of data precluded a lengthier lag. As more data is collected over time, a greater lag treatment will be possible which should provide a more accurate estimate of the impact of electricity prices.

Projected electricity prices are assumed to increase at the rate of inflation. Consequently, the real price is projected to be essentially constant.

3.5 Overview of Results

The results of the forecast show that the calendar year ARP net energy for load is expected to grow at an annual average growth rate of 2.4 percent from 2004-2013, and then decrease in the level of growth to 2.2 percent through 2023. On a normal weather basis the calendar year 2004 net energy for load and coincident peak supplied from the ARP are 6,952 GWh and 1,392 MW (winter peak), respectively.

3.6 Uncertainty of the Forecast

While a forecast that is derived from econometric equations provides a sound basis for planning, it is recognized that the forecasting equations are likely to be no more accurate than they have proved to be over the study period. At the direction of FMPA staff, Beck has produced high and low range results that address the potential error in the regression equations. The variance of these results is based on the estimated standard error of the regression equations and is intended to capture approximately 67 percent of occurrences.

3.7 Conclusions and Recommendations

The results of this forecast have been influenced by several factors including data integrity, economic projections, and local knowledge. Each of these factors brings elements of bias and error, only some of which is controllable. To the extent that bias and error are removed from the forecast, the ability of the forecast to predict future load and energy requirements improves.

The econometric methods used in this body of work thrive on large amounts of data. The larger the amount of data, the more likely it is that useful, stable relationships can be drawn from the data. In addition to the amount of data, the more closely the data represent what actually happened historically (and what will happen in the future), the better the models will be at predicting future load and energy requirements.

In this forecast, Beck relied on economic projections provided by Economy.com. Though Economy.com is a recognized provider used by many Florida utilities, they seem unlikely to inject significant local knowledge into their economic projections. To the extent that county-level economics are not representative of ARP member economics, the forecasting models may be biased. In addition, due to the lag of economic data reporting, the last two years or more of historical economic data are actually projections. To the extent that the projections of historical economics differ from actual economics, the forecasting models will be affected.

As a general rule, local knowledge can play a significant role in developing reliable forecasting models. Local knowledge adds both a deeper understanding of historical data behavior and relationships and a useful expectation regarding how both are likely to change in the future. However, adjustments to forecasting models or underlying data should be made with considerable care.

Overall, it is important to remember that the load forecast is an annual process. As projections become historical values, uncertainties in the current near term will diminish and be replaced with other uncertainties. However, barring significant and lasting changes to the underlying relationships, the econometric load forecast is a prudent and reliable means of forecasting load and energy.

Tables 3-1 through 3-6 present the base case load forecast. Tables 3-7 through 3-9 present the high load forecast, and Tables 3-10 through 3-12 present the low load forecast. Table 3-13 presents the base case monthly load forecast.

Table 3-1 (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
1994			962	74,817	12,860	1,091	14,179	76,960
1995			1,041	76,070	13,690	1,146	13,766	83,250
1996			1,072	77,423	13,840	1,163	14,141	82,210
1997			1,234	103,507	11,920	1,380	19,723	69,960
1998			1,878	141,969	13,230	1,919	27,302	70,280
1999			1,980	151,969	13,030	2,318	28,789	80,520
2000			2,065	154,938	13,330	2,448	29,518	82,930
2001			2,105	156,751	13,430	2,466	30,097	81,940
2002			2,359	173,977	13,560	2,803	33,211	84,400
2003			3,138	227,099	13,820	3,271	43,374	75,413
2004			3,120	230,661	13,525	3,327	43,801	75,946
2005			3,184	234,264	13,591	3,371	44,301	76,097
2006			3,277	239,341	13,692	3,457	45,228	76,435
2007			3,358	243,420	13,797	3,521	45,852	76,799
2008			3,443	247,468	13,914	3,592	46,540	77,191
2009			3,568	254,104	14,040	3,676	47,529	77,343
2010			3,665	258,577	14,175	3,752	48,192	77,851
2011			3,766	263,295	14,304	3,834	48,892	78,422
2012			3,870	268,081	14,436	3,919	49,590	79,024
2013			3,978	273,207	14,561	4,006	50,311	79,630

Table 3-2 (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)
	Industrial						
Year	GWh	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 Customers GWh
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					32	22	4,567
2001					33	22	4,626
2002					36	24	5,222
2003					47	58	6,514
2004					47	61	6,554
2005					47	63	6,665
2006					47	65	6,846
2007					48	67	6,995
2008					48	68	7,152
2009					49	70	7,362
2010					49	72	7,538
2011					50	73	7,723
2012					50	75	7,914
2013					50	77	8,112

Table 3-3 (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
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		271	4,838		184,456
2001		240	4,866		186,848
2002		300	5,522		207,188
2003		474	6,988		270,473
2004		398	6,952		274,462
2005		404	7,069		278,565
2006		415	7,262		284,569
2007		424	7,419		289,273
2008		434	7,586		294,008
2009		448	7,810		301,633
2010		459	7,996		306,768
2011		470	8,193		312,187
2012		482	8,396		317,671
2013		494	8,606		323,517

Table 3-4 (Schedule 3.1).
History and Forecast of Summer Peak Demand (MW)
All-Requirements Project – Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
1994	454								454
1995	504								504
1996	509								509
1997	643								643
1998	947								947
1999	982								982
2000	972								972
2001	965								965
2002	992								992
2003	1,340								1,340
2004	1,385								1,385
2005	1,407								1,407
2006	1,445								1,445
2007	1,476								1,476
2008	1,509								1,509
2009	1,554								1,554
2010	1,591								1,591
2011	1,629								1,629
2012	1,670								1,670
2013	1,711								1,711

Table 3-5 (Schedule 3.2).
History and Forecast of Winter Peak Demand (MW)
All-Requirements Project – Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
1993/94	442								442
1994/95	502								502
1995/96	553								553
1996/97	499								499
1997/98	686								686
1998/99	926								926
1999/00	948								948
2000/01	1,008								1,008
2001/02	1,007								1,007
2002/03	1,473								1,473
2003/04	1,392								1,392
2004/05	1,414								1,414
2005/06	1,452								1,452
2006/07	1,483								1,483
2007/08	1,515								1,515
2008/09	1,562								1,562
2009/10	1,598								1,598
2010/11	1,636								1,636
2011/12	1,676								1,676
2012/13	1,717								1,717

Table 3-6 (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)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1994	2,188						2,188	55%
1995	2,363						2,363	54%
1996	2,405						2,405	54%
1997	2,850						2,850	51%
1998	4,530						4,530	55%
1999	4,657						4,657	54%
2000	4,838						4,838	57%
2001	4,866						4,866	58%
2002	5,541						5,541	64%
2003	7,019						7,019	60%
2004	6,952						6,952	58%
2005	7,069						7,069	58%
2006	7,262						7,262	58%
2007	7,419						7,419	58%
2008	7,586						7,586	58%
2009	7,810						7,810	58%
2010	7,996						7,996	58%
2011	8,193						8,193	58%
2012	8,396						8,396	58%
2013	8,606						8,606	58%

Table 3-7 (Schedule 3.1a). Forecast of Summer Peak Demand (MW) All-Requirements Project – High Case									
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2004	1,466								1,466
2005	1,490								1,490
2006	1,531								1,531
2007	1,565								1,565
2008	1,600								1,600
2009	1,648								1,648
2010	1,687								1,687
2011	1,729								1,729
2012	1,772								1,772
2013	1,817								1,817

Table 3-8 (Schedule 3.2a).
Forecast of Winter Peak Demand (MW)
All-Requirements Project – High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2003/04	1,474								1,474
2004/05	1,498								1,498
2005/06	1,539								1,539
2006/07	1,573								1,573
2007/08	1,607								1,607
2008/09	1,658								1,658
2009/10	1,696								1,696
2010/11	1,737								1,737
2011/12	1,780								1,780
2012/13	1,824								1,824

Table 3-9 (Schedule 3.3a).
Forecast of Annual Net Energy for Load (GWh)
All-Requirements Project – High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2004	7,361						7,361	57%
2005	7,489						7,489	57%
2006	7,697						7,697	57%
2007	7,865						7,865	57%
2008	8,045						8,045	57%
2009	8,285						8,285	57%
2010	8,486						8,486	57%
2011	8,698						8,698	57%
2012	8,916						8,916	57%
2013	9,142						9,142	57%

Table 3-10 (Schedule 3.1b).
Forecast of Summer Peak Demand (MW)
All-Requirements Project – Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2004	1,305								1,305
2005	1,325								1,325
2006	1,359								1,359
2007	1,389								1,389
2008	1,419								1,419
2009	1,461								1,461
2010	1,495								1,495
2011	1,531								1,531
2012	1,568								1,568
2013	1,607								1,607

Table 3-11 (Schedule 3.2b).
Forecast of Winter Peak Demand (MW)
All-Requirements Project – Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Load Conservation	Net Firm Demand
2003/04	1,310								1,310
2004/05	1,330								1,330
2005/06	1,365								1,365
2006/07	1,394								1,394
2007/08	1,424								1,424
2008/09	1,467								1,467
2009/10	1,501								1,501
2010/11	1,536								1,536
2011/12	1,572								1,572
2012/13	1,610								1,610

Table 3-12 (Schedule 3.3b).
Forecast of Annual Net Energy for Load (GWh)
All-Requirements Project – Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)
	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2004	6,546						6,546	57%
2005	6,652						6,652	57%
2006	6,830						6,830	57%
2007	6,976						6,976	57%
2008	7,131						7,131	57%
2009	7,339						7,339	57%
2010	7,511						7,511	57%
2011	7,693						7,693	57%
2012	7,880						7,880	57%
2013	8,073						8,073	57%

Table 3-13 (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 - 2003		Forecast - 2004		Forecast - 2005	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,477	574	1,392	553	1,414	561
February	901	447	1,083	459	1,100	465
March	1,134	534	1,026	526	1,042	534
April	1,078	516	1,133	516	1,151	524
May	1,264	650	1,248	606	1,268	615
June	1,329	640	1,305	615	1,325	626
July	1,340	694	1,385	712	1,407	724
August	1,309	678	1,361	716	1,382	729
September	1,262	637	1,300	636	1,321	648
October	1,160	584	1,132	588	1,151	598
November	1,098	516	941	491	963	500
December	1,106	518	1,102	534	1,126	544

FMPA

Florida Municipal Power Agency

Section 4.0

Conservation Programs

Community Power + Statewide Strength

4.0 CONSERVATION PROGRAMS

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 videotape. Additionally, bill inserts have been utilized to keep customers aware of available conservation programs. FMPA will continue to offer 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.

4.1 Existing Demand-Side Management Programs

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

4.1.1 Residential Demand-Side Management Programs

- 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 will receive a fixed monthly credit on their bill for each device under control. In general, direct load control is being phased out by ARP members primarily due to obsolescence of equipment.
- Residential Energy Audits Program: This program offers a walk-through audit to identify energy savings opportunities. The Energy Star program has been offered since October, 1999.

- Natural Gas Promotion: During Energy Audits, it is recommended to convert old, inefficient electric heat and water heaters to natural gas when the conversion would benefit the customer.
- High-Pressure Sodium Outdoor Lighting Conversion: This program replaces mercury-vapor street lights with high-pressure sodium lights.
- Fix-Up Program for the Elderly and Handicapped: This program includes weatherization measures that target low-income housing.

4.1.2 Commercial Demand-Side Management Programs

- 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.
- 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.

Florida Municipal Power Agency

Section 5.0

Forecast of Facilities Requirements

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5.0 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 opportunities 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 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 percent 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 2006 (22 MW of combustion turbine capacity), 2008 (308 MW of combustion turbine capacity), 2010 (140 MW of combustion turbine capacity), 2011 (84 MW of combustion turbine capacity), 2012 (22 MW of combustion turbine capacity), and 2013 (84 MW of combustion turbine capacity). FMPA's most recent capacity addition is represented by its share of Stanton Energy Center Unit A (Stanton A), a 633 MW gas-fired combined cycle unit which began commercial operation on October 1, 2003. Stanton A is jointly owned by FMPA, KUA, OUC, and Southern-Florida. Combined, FMPA and KUA own seven percent of Stanton A, and purchase an additional 13 percent of the unit's capacity under a ten-year power purchase agreement with various provisions for capacity reductions as well as contract extensions. FMPA is also beginning the process to add a 22 MW combustion turbine at Stock Island in the summer of 2006, as alluded to above. Additionally, generation can be added at the Cane Island Power Park, at Fort Pierce Utilities Authority's Power Plant, at Lake Worth Utilities, at Vero Beach's Power Plant, and at Keys Energy Services' Stock Island Plant. Further, reciprocating engines or small combustion turbine generation can be installed on all fifteen ARP member systems.

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 at which generation is planned to be added as conditions change. Worthy of note is FMPA's awareness of the potential benefits of increased fuel diversity among its generating portfolio, which has prompted FMPA to consider a solid-fuel capacity addition. Due to permitting and scheduling constraints, commercial operation of such a unit, if ultimately decided upon, would not be feasible until the summer of 2010 at the earliest. Nonetheless, consideration and further study of the potential benefits related to construction of a new solid-fueled unit are appropriate from FMPA's perspective.

Table 5-1 (Schedule 5)
Fuel Requirements – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		**Units**	**Actual 2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
(1)	Nuclear[1]		Trillion BTU	7.20	7.06	7.09	7.25	6.91	7.28	7.09	7.07	7.09	7.28	6.89
(2)	Coal		1000 Ton	567	680	682	684	685	682	683	683	685	688	686
	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	0
	Distillate													
(7)		Steam	1000 BBL											
(8)		CC	1000 BBL											
(9)		CT	1000 BBL	128	271	330	406	448	466	554	653	785	762	780
(10)		TOTAL	1000 BBL	128	271	330	406	448	466	554	653	785	762	780
	Natural Gas													
(11)		Steam	1000 MCF	456	404	449	327	478	123	71	156	178	152	166
(12)		CC	1000 MCF	14,574	20,379	20,817	21,006	22,342	23,919	24,314	26,407	27,147	27,259	27,549
(13)		CT	1000 MCF	507	400	373	248	369	5,071	6,855	11,820	16,070	17,867	22,323
(14)		TOTAL	1000 MCF	15,537	21,182	21,639	21,580	23,189	29,113	31,240	38,383	43,395	45,278	50,038
(15)	Other (Specify)		Trillion BTU											

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

Table 5-2 (Schedule 6.1)
Energy Sources (GWh) – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		**Units**	**Actual 2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
(1)	Annual Firm Inter-Region Interchange		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear[1]		GWh	670	656	660	675	643	677	660	658	660	677	641
(3)	Coal		GWh	1,388	1,667	1,671	1,676	1,678	1,672	1,674	1,674	1,679	1,686	1,682
	Residual													
(4)		Steam	GWh											
(5)		CC	GWh											
(6)		CT	GWh											
(7)		TOTAL	GWh	0	0	0	0	0	0	0	0	0	0	0
	Distillate													
(8)		Steam	GWh											
(9)		CC	GWh											
(10)		CT	GWh	22	47	57	70	77	80	96	113	135	131	135
(11)		TOTAL	GWh	22	47	57	70	77	80	96	113	135	131	135
	Natural Gas													
(12)		Steam	GWh	38	34	37	27	40	10	6	13	15	13	14
(13)		CC	GWh	2,082	2,911	2,974	3,001	3,192	3,417	3,473	3,772	3,878	3,894	3,936
(14)		CT	GWh	39	31	29	23	34	461	623	1,075	1,461	1,624	2,029
(15)		TOTAL	GWh	2,159	2,976	3,040	3,051	3,265	3,888	4,102	4,860	5,354	5,531	5,979
(16)	NUG		GWh											
(17)	HYDRO		GWh											
(18)	Interchange		GWh	2,749	1,606	1,640	1,790	1,754	1,269	1,278	691	365	370	168
(19)	Net Energy for Load		GWh	6,988	6,952	7,068	7,262	7,418	7,586	7,810	7,996	8,193	8,395	8,605

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

Table 5-3 (Schedule 6.2)
Energy Sources (%) – All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		**Units**	**Actual 2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
(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%	0.0%
(2)	Nuclear[1]		%	9.6%	9.4%	9.3%	9.3%	8.7%	8.9%	8.4%	8.2%	8.1%	8.1%	7.5%
(3)	Coal		%	19.9%	24.0%	23.6%	23.1%	22.6%	22.0%	21.4%	20.9%	20.5%	20.1%	19.5%
	Residual													
(4)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distillate													
(8)		Steam	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	%	0.3%	0.7%	0.8%	1.0%	1.0%	1.1%	1.2%	1.4%	1.7%	1.6%	1.6%
(11)		TOTAL	%	0.3%	0.7%	0.8%	1.0%	1.0%	1.1%	1.2%	1.4%	1.7%	1.6%	1.6%
	Natural Gas													
(12)		Steam	%	0.5%	0.5%	0.5%	0.4%	0.5%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%
(13)		CC	%	29.8%	41.9%	42.1%	41.3%	43.0%	45.0%	44.5%	47.2%	47.3%	46.4%	45.7%
(14)		CT	%	0.6%	0.4%	0.4%	0.3%	0.5%	6.1%	8.0%	13.4%	17.8%	19.3%	23.6%
(15)		TOTAL	%	30.9%	42.8%	43.0%	42.0%	44.0%	51.3%	52.5%	60.8%	65.3%	65.9%	69.5%
(16)	NUG		%	0.0%	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%	0.0%
(18)	Interchange		%	39.3%	23.1%	23.2%	24.7%	23.6%	16.7%	16.4%	8.6%	4.5%	4.4%	2.0%
(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%	100.0%

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

Table 5-4 (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)
	Total Installed Capacity[2]	Firm Capacity Import[3]	Firm Capacity Export	QF	Total Available Capacity	System Firm Summer Peak Demand[4]	Reserve Margin before Maintenance[1]		Scheduled Maintenance	Reserve Margin after Maintenance[1]	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2004	1,395	305	0	0	1,701	1,401	333	24%	0	333	24%
2005	1,395	328	0	0	1,724	1,424	336	24%	0	336	24%
2006	1,410	357	0	0	1,767	1,461	343	23%	0	343	23%
2007	1,407	335	0	0	1,742	1,494	273	18%	0	273	18%
2008	1,715	145	0	0	1,860	1,527	344	23%	0	344	23%
2009	1,715	145	0	0	1,860	1,572	297	19%	0	297	19%
2010	1,855	45	0	0	1,900	1,609	300	19%	0	300	19%
2011	1,939	45	0	0	1,984	1,648	345	21%	0	345	21%
2012	1,960	45	0	0	2,006	1,689	326	19%	0	326	19%
2013	2,044	0	0	0	2,045	1,732	313	18%	0	313	18%

1. Reserve Margin includes reserves associated with partial requirements purchases.
2. Includes member owned capacity and a 22 MW CT at Key West (Stock Island) in 2006, an 140 MW CT at Cane Island in 2008, an 84 MW CT at Ft. Pierce (H.D. King) in 2008, an 84 MW CT at Lake Worth (Tom G. Smith) in 2008, a 140 MW CT at Cane Island in 2010, an 84 MW CT at Vero Beach in 2011, a 22 MW CT at Key West (Stock Island) in 2012, and an 84 MW CT at Ft. Pierce (H.D. King) in 2013.
3. Includes no undesignated power purchases.
4. Includes Net Firm Demand and system losses.

Table 5-5 (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)
Year	Total Installed Capacity[2] MW	Firm Capacity Import[3] MW	Firm Capacity Export MW	QF MW	Total Available Capacity MW	System Firm Winter Peak Demand[4] MW	Reserve Margin before Maintenance[1] MW	Reserve Margin before Maintenance[1] % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance[1] MW	Reserve Margin after Maintenance[1] % of Peak
2003/04	1,451	305	0	0	1,756	1,408.3	386	27%	0	386	27%
2004/05	1,451	293	0	0	1,745	1,430.7	351	25%	0	351	25%
2005/06	1,444	357	0	0	1,801	1,468.9	373	25%	0	373	25%
2006/07	1,463	335	0	0	1,798	1,500.5	327	22%	0	327	22%
2007/08	1,638	145	0	0	1,783	1,532.9	258	17%	0	258	17%
2008/09	1,832	145	0	0	1,977	1,580.4	408	26%	0	408	26%
2009/10	1,832	45	0	0	1,877	1,616.9	268	17%	0	268	17%
2010/11	2,007	45	0	0	2,052	1,655.4	408	25%	0	408	25%
2011/12	2,104	45	0	0	2,149	1,695.0	466	28%	0	466	28%
2012/13	2,125	45	0	0	2,170	1,736.4	445	26%	0	445	26%

1. Reserve Margin includes reserves associated with partial requirements purchases.
2. Includes member owned capacity and a 22 MW CT at Key West (Stock Island) in 2006, an 140 MW CT at Cane Island in 2008, an 84 MW CT at Ft. Pierce (H.D. King) in 2008, an 84 MW CT at Lake Worth (Tom G. Smith) in 2008, a 140 MW CT at Cane Island in 2010, an 84 MW CT at Vero Beach in 2011, a 22 MW CT at Key West (Stock Island) in 2012, and an 84 MW CT at Ft. Pierce (H.D. King) in 2013.
3. Includes no undesignated power purchases.
4. Includes Net Firm Demand and system losses.

FMPA

Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

Community Power + Statewide Strength

6.0 SITE AND FACILITY DESCRIPTIONS

Stanton Energy Center Combined Cycle Unit A (Stanton A)

Stanton A, a 633 MW generating unit, is located at the Stanton Energy Center site located on the eastern side of the service territory of the Orlando Utilities Commission. Stanton A utilizes a 2x1 combined cycle configuration with two General Electric PG-7231 FA combustion turbines, two heat recovery steam generators, and a steam turbine. Stanton A is equipped with evaporative inlet cooling, duct firing, and power augmentation to increase output. Natural gas is the primary fuel and No. 2 fuel oil can be utilized as the backup fuel. Stanton A is not equipped with bypass stacks and dampers, but the condenser is sized such that both combustion turbines can be operated at full load with the steam turbine out of service. Stanton A is jointly owned by FMPA, KUA, OUC, and Southern-Florida, with FMPA and KUA owning a combined seven percent of the unit's capacity and purchasing a combined 13 percent under a ten-year power purchase agreement with provisions for both capacity reductions and term extensions.

Cane Island

Cane Island Power Park is located south and west of the Kissimmee Utility Authority's (KUA) service area and contains 380 MW (summer) of gas turbine and combined cycle capacity. The Cane Island Power Park consists of a simple cycle gas turbine and two combined cycle generating units, each of which is 50 percent owned by FMPA and 50 percent owned by KUA. Cane Island Unit 3, the newest unit at the site, began commercial operation in January, 2002. The Cane Island Power Park is the assumed location of two new General Electric 7FA combustion turbine additions, the first of which is planned for the winter of 2008, with the second following in the summer of 2010.

Stock Island Combustion Turbines 4 and 5 (Keys Energy Services)

A combustion turbine unit (22 MW) will most likely be located at the Keys Energy Services Stock Island Plant in Monroe County with a commercial in-service date of summer 2006. A second addition is also being tentatively planned for commercial operation in the summer of 2012. The units are planned to be similar to Stock Island Units CT 2 & 3, which were placed in operation during 1999.

H.D. King Power Plant (Ft. Pierce)

The H.D. King Power Plant is located in the City of Fort Pierce's service area in St. Lucie County and currently consists of 118 MW of steam, combined cycle, and reciprocating engine generation. The site is suitable for possible future repowering or addition of new combustion turbines or combined cycle capacity. For purposes of this Ten-Year Site Plan, it has been assumed that 84 MW (summer) of simple cycle capacity will be added to the site in the summer of 2008, with an additional 84 MW (summer) of simple cycle capacity added during the summer of 2013.

Tom G. Smith Power Plant (Lake Worth)

The Tom G. Smith Power Plant is located in the City of Lake Worth's service area in Palm Beach County and currently consists of 88 MW of steam, combined cycle, and reciprocating engine generation. The site is suitable for possible future repowering or addition of new combustion turbines or combined cycle capacity. For purposes of this Ten-Year Site Plan, it has been assumed that 84 MW (summer) of simple cycle capacity will be added to the site in the summer of 2008.

Vero Beach Power Plant Site

The Vero Beach Power Plant Site is located in the City of Vero Beach's service area in Indian River County and currently consists of 150 MW of steam, combined cycle, and reciprocating engine generation and is suitable for possible future repowering or addition of new combustion turbines or combined cycle units. For purposes of this Ten-Year Site Plan, it has been assumed that 84 MW (summer) of simple cycle capacity will be added to the site in the summer of 2011.

Table 6-1 (Schedule 8)
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		
Plant Name	Unit No.	Location (County)	Unit Type	Primary	Alt.	Primary	Alt.		MM/YY	MM/YY	kW	Summer MW	Winter MW	Status
Stock Island	CT4	Monroe	CT	FO2	-	WA	-		6/06	UNK	UNK	22.0	22.0	P
Cane Island	CT	Osceola	CT	NG	FO2	PL	TK		01/08	UNK	UNK	140.0	175.0	P
H. D. King	CT	St. Lucie	CT	NG	FO2	PL	TK		06/08	UNK	UNK	84.0	97.0	P
Tom G. Smith	CT	Palm Beach	CT	NG	FO2	PL	TK		06/08	UNK	UNK	84.0	97.0	P
Cane Island	CT	Osceola	CT	NG	FO2	PL	TK		06/10	UNK	UNK	140.0	175.0	P
Municipal Plant	CT	Indian River	CT	NG	FO2	PL	TK		06/11	UNK	UNK	84.0	97.0	P
Stock Island	CT5	Monroe	CT	FO2	-	WA	-		6/12	UNK	UNK	22.0	22.0	P
H. D. King	CT	St. Lucie	CT	NG	FO2	PL	TK		06/13	UNK	UNK	84.0	97.0	P

Table 6-2 (Schedule 9.1)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Stock Island CT4
(2)	**Capacity**	
	a. Summer	22
	b. Winter	22
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jun-05
	b. Commercial In-Service Date	Jun-06
(5)	**Fuel**	
	a. Primary Fuel	No. 2 oil
	b. Alternate Fuel	N/A
(6)	**Air Pollution Control Strategy**	Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	Applications being prepared
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	0.0%
	Equivalent Availability Factor (EAF)	97.0%
	Resulting Capacity Factor	35.0%
	Average Net Operating Heat Rate (ANOHR)	10,931 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	513
	Direct Construction Cost (2004 $/kW)	459
	AFUDC Amount ($/kW)	41
	Escalation ($/kW)	13
	Fixed O&M ($/kW)	0
	Variable O&M ($/MWh)	5

Table 6-3 (Schedule 9.2)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	H. D. King CT
(2)	**Capacity**	
	a. Summer	84
	b. Winter	97
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-07
	b. Commercial In-Service Date	Jun-08
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	17.5%
	Average Net Operating Heat Rate (ANOHR)	9,729 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	657
	Direct Construction Cost (2004 $/kW)	542
	AFUDC Amount ($/kW)	53
	Escalation ($/kW)	62
	Fixed O&M ($/kW)	13
	Variable O&M ($/MWh)	6

Table 6-4 (Schedule 9.3)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Cane Island CT
(2)	**Capacity**	
	a. Summer	140
	b. Winter	175
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jun-06
	b. Commercial In-Service Date	Jan-08
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	12.5%
	Average Net Operating Heat Rate (ANOHR)	11,250 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	521
	Direct Construction Cost (2004 $/kW)	442
	AFUDC Amount ($/kW)	42
	Escalation ($/kW)	37
	Fixed O&M ($/kW)	9
	Variable O&M ($/MWh)	9

Table 6-5 (Schedule 9.4)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Tom G. Smith CT
(2)	**Capacity**	
	a. Summer	84
	b. Winter	97
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-07
	b. Commercial In-Service Date	Jun-08
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	17.5%
	Average Net Operating Heat Rate (ANOHR)	9,729 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	657
	Direct Construction Cost (2004 $/kW)	542
	AFUDC Amount ($/kW)	53
	Escalation ($/kW)	62
	Fixed O&M ($/kW)	13
	Variable O&M ($/MWh)	6

Table 6-6 (Schedule 9.5)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Cane Island CT
(2)	**Capacity**	
	a. Summer	140
	b. Winter	175
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-09
	b. Commercial In-Service Date	Jun-10
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	12.5%
	Average Net Operating Heat Rate (ANOHR)	11,250 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	561
	Direct Construction Cost (2004 $/kW)	439
	AFUDC Amount ($/kW)	45
	Escalation ($/kW)	77
	Fixed O&M ($/kW)	9
	Variable O&M ($/MWh)	9

Table 6-7 (Schedule 9.6)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Municipal Plant CT
(2)	**Capacity**	
	a. Summer	84
	b. Winter	97
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-10
	b. Commercial In-Service Date	Jun-11
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	17.5%
	Average Net Operating Heat Rate (ANOHR)	9,729 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	707
	Direct Construction Cost (2004 $/kW)	538
	AFUDC Amount ($/kW)	57
	Escalation ($/kW)	112
	Fixed O&M ($/kW)	13
	Variable O&M ($/MWh)	6

Table 6-8 (Schedule 9.7)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	Stock Island CT5
(2)	**Capacity**	
	a. Summer	22
	b. Winter	22
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jun-11
	b. Commercial In-Service Date	Jun-12
(5)	**Fuel**	
	a. Primary Fuel	No. 2 oil
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	0.0%
	Equivalent Availability Factor (EAF)	97.0%
	Resulting Capacity Factor	35.0%
	Average Net Operating Heat Rate (ANOHR)	10,931 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	20
	Total Installed Cost (In-Service Year $/kW)	594
	Direct Construction Cost (2004 $/kW)	531
	AFUDC Amount ($/kW)	48
	Escalation ($/kW)	15
	Fixed O&M ($/kW)	0
	Variable O&M ($/MWh)	5

Table 6-9 (Schedule 9.8)
Status Report and Specifications of Proposed Generating Facilities – All-Requirements Project
(Preliminary Information)

(1)	**Plant Name and Unit Number**	H. D. King CT
(2)	**Capacity**	
	a. Summer	84
	b. Winter	97
(3)	**Technology Type**	CT
(4)	**Anticipated Construction Timing**	
	a. Field Construction Start Date	Jan-12
	b. Commercial In-Service Date	Jun-13
(5)	**Fuel**	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 oil
(6)	**Air Pollution Control Strategy**	Low NO_x Combustors, Water Injection
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	N/A
(9)	**Construction Status**	Planned
(10)	**Certification Status**	N/A
(11)	**Status with Federal Agencies**	N/A
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF)	3.0%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor (EAF)	94.0%
	Resulting Capacity Factor	17.5%
	Average Net Operating Heat Rate (ANOHR)	9,729 Btu/kWh
(13)	**Projected Unit Financial Data**	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW)	743
	Direct Construction Cost (2004 $/kW)	536
	AFUDC Amount ($/kW)	59
	Escalation ($/kW)	148
	Fixed O&M ($/kW)	13
	Variable O&M ($/MWh)	6

Table 6-10 (Schedule 10) Status Report and Specifications of Proposed Directly Associated Transmission Lines All-Requirements Project		
(1)	**Point of Origin and Termination**	FMPA has no Proposed Transmission Lines for inclusion in Schedule 10.
(2)	**Number of Lines**	N/A
(3)	**Right-of-Way**	N/A
(4)	**Line Length**	N/A
(5)	**Voltage**	N/A
(6)	**Anticipated Construction Timing**	N/A
(7)	**Anticipated Capital Investment**	N/A
(8)	**Substations**	N/A
(9)	**Participation with Other Utilities**	N/A

Community Power + Statewide Strength

APPENDIX I. PLANNED AND PROPOSED TRANSMISSION ADDITIONS

Table I-1 presented 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 Regional Transmission Organization (RTO) *Grid Florida*, it was considered necessary to document these plans in the public record.

Table I-1.
Planned and Proposed Transmission Additions for FMPA Members
2004 through 2013 (69kV and above)

City	From	To	Voltage	Circuit	Estimated In-Service Date
Ft. Pierce	Hartman Auto-Xfmr1Upgrade		138/69		9/2007
	Hartman Auto-Xfmr2 Upgrade		138/69		9/2007
	King (Reconductor)	Garden City	69	1	9/2009
	King (Reconductor)	Savannah	69	1	9/2009
Homestead	Redland	Lucy	138 kV	1	12/2005
	Redland	McMinn	138 kV	1	12/2005
Jacksonville Beach	Jacksonville Beach (Reconductor)	Neptune	138 kV	1	6/2008
Key West & FKEC	Tavernier	Islamorada	138 kV	2	6/2008
	Islamorada	Marathon	138 kV	1	6/2008
	Florida City	Tavernier	138 kV	2	6/2018
	Tavernier		Ring Bus		6/2018
	Marathon		Var Improvements		2005
	Big Pine		Var Improvements		2005
	Big Coppitt		Var Improvements		2005
	KWD Transformer		69/13.8kV		2005
	SIS 4th Ave Transformer		69/13.8kV		2008
Kissimmee	Clay Auto-Transformer		230/69 kV		6/2010
	Clay (Reconductor)	Hansel	69 kV	1	6/2010
	Clay (Reconductor)	Airport	69 kV	1	6/2010
	Hansel (Reconductor)	C.A.Wall	69 kV	1	6/2010
	Auto-Transformer @South-West (OUC)		230/69 kV		6/2010
	Hord	South-West (OUC)	69 kV	1	6/2010
	Lake Cecile	South-West (OUC)	69 kV	1	6/2010
Lake Worth	Main Plant Transformer		138/26 kV		6/2005
	Canal Transformer		138/26 kV		12/2005
	Hypoluxo	Canal	138 kV	1	12/2005

Table I-1 (continued).
Planned and Proposed Transmission Additions for FMPA Members
2004 through 2013 (69kV and above)

City	From	To	Voltage	Circuit	Estimated In-Service Date
New Smyrna Beach	30 MVA Transformer		115/23 kV		6/2005
	Smyrna	Cassadega	115 kV	2	1/2007
Ocala	Ergle	Silver Springs North	230 kV	2	12/2004
	Ergle Auto-Transformer		230/69 kV		12/2004
	Ocala Palms	Airport	69 kV	1	12/2004
	Ocala Palms	Richmond	69 kV	1	12/2004
	Nuby's Corner Substation		69 kV		12/2004
	Nuby's Corner	Silver Springs	69 kV	1	12/2004
	Nuby's Corner	Baseline Rd	69 kV	1	12/2005
	Ocala Springs Substation		69 kV		6/2007
	Ocala Springs	Ergle	69 kV	1	6/2007
	Ocala Springs	Silver Springs	69 kV	1	6/2007
	Dearmin	Baseline Rd	69 kV	1	6/2008
	Dearmin / Baseline Substation (Improvements)		69 kV		6/2008
	Fore Corners Substation		69 kV		6/2011
	Fore Corners	Ergle	69 kV	1	6/2011
	Fore Corners	Ocala North	69 kV	1	6/2011
	Red Oak	Silver Springs	230 kV	1	6/2012
	Red Oak Auto-Transformer		230/69 kV		6/2013
Vero Beach	Sub #6	Sub #1	69 kV	1	6/2006