FMPA

Florida Municipal Power Agency

Ten-Year Site Plan

April 2008

Community Power + Statewide Strength

Florida Municipal Power Agency

Ten-Year Site Plan 2008-2017

Submitted to

Florida Public Service Commission

April 1, 2008

Community Power + Statewide Strength

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Table of Contents

Community Power + Statewide Strength

Table of Contents

List of Figures, Tables and Required Schedules

Appendices

Florida Municipal Power Agency

Executive Summary

Community Power + Statewide Strength

Executive Summary

The following information is provided in accordance with Florida Public Service Commission (PSC) 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 (TYSP). The TYSP 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 and transmission additions.

The Florida Municipal Power Agency (FMPA or the Agency) 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 15 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 whereby each member can elect whether or not to participate. This report presents planning information for the ARP and on the other existing Agency projects.

The ARP and other existing Agency summer capacity resources for the year 2008 total 1,916 MW. This capacity is comprised of "excluded" nuclear resources, member-owned resources, ARP-owned resources, and purchase power, and is summarized below in Table ES-1.

Table ES-1
FMPA Summer 2008 Capacity Resources

Resource Category	Summer Capacity (MW)
Nuclear	84
ARP Ownership	865
Member Ownership	557
Purchase Power	410
Total 2008 ARP Resources	1,916

FMPA has a total of 913 MW of power supply projects currently under construction or planned for construction. Future ARP TYSP expansion resources are presented below in Table ES-2.

Table ES-2
FMPA Planned Expansion Resources

Unit Description	Commercial Operation (MM/YY)	Summer Capacity (MW)
Treasure Coast Energy Center Unit 1	05/08	296
Cane Island Unit 4	05/11	296
Peaking Unit	06/12	86
Peaking Unit	06/13	149
Peaking Unit	06/15	86
Total		913

FMPA will soon add capacity from the Treasure Coast Energy Center (TCEC), a natural gas fired 296 MW combined cycle unit that FMPA is developing at a site in Fort Pierce. FMPA received site certification in June 2006, and physical construction began on TCEC Unit 1 in August 2006. Construction is on schedule, with an in-service date for TCEC Unit 1 of May 2008.

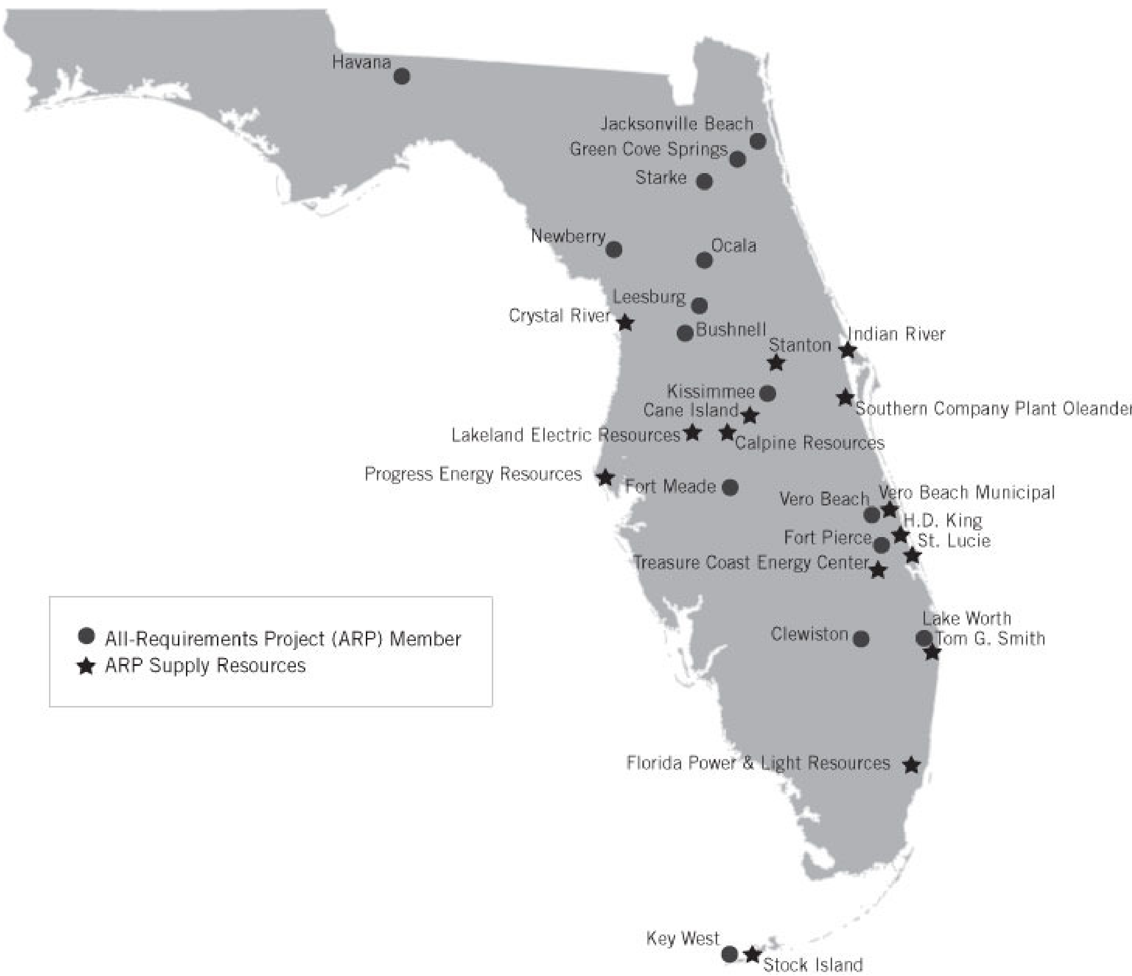
FMPA issued a Request for Power Supply Proposals (Power Supply RFP) in June 2007. The purpose of the Power Supply RFP was to determine whether a sufficient and cost-effective source of capacity and energy could be obtained as a replacement for Cane Island Unit 4, planned for commercial operation in 2011. No bids were received in response to this RFP. FMPA plans to submit a "Need for Power" application (Need Determination) for Cane Island Unit 4 to the PSC in mid-2008.

FMPA will continue to pursue sufficient and cost-effective alternatives to the peaking units that are planned for commercial operation in 2012, 2013, and 2015. Based on the outcome of these investigations, FMPA will determine whether to delay the in-service dates for these units.

FMPA participates in "Green Energy" through renewable power purchases and member conservation programs. FMPA receives renewable energy from two renewable power purchases FMPA receives power from a cogeneration plant owned and operated by U.S. Sugar Corporation that is fueled by sugar bagasse, a byproduct of sugar production. The second renewable resource utilizes landfill gas provided by the Orange County Landfill to supplement the coal requirements of the Stanton Energy Center, which is partially owned by FMPA. FMPA and its members continue to investigate additional sources of "Green Energy" through renewable power projects or conservation programs.

A location map of the ARP members and FMPA's power resources is shown in Figure ES-1 below.

Figure ES-1
ARP Member and FMPA Power Supply Resource Locations



Florida Municipal Power Agency

Section 1.0

Description of FMPA

Community Power + Statewide Strength

Section 1 Description of FMPA

1.1 FMPA

Florida Municipal Power Agency (FMPA) is a governmental wholesale power company owned by municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities.

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. This 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, Chapter 361, Part II, Florida Statutes, and the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes.

The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on the 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.

Each city commission, utility commission, or authority that 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 approving FMPA's project budgets (except for the All-Requirements Power Supply Project budget which is approved by the Executive Committee), approving new projects and project financing (except for All-Requirements Power Supply Project financing which is approved by the Executive Committee), hiring a General Manager and General Counsel, establishing by-laws that govern how FMPA operates, and creating policies that implement such by-laws. At its annual meeting, the Board elects a Chairperson, Vice Chairperson, Secretary, and Treasurer.

The Executive Committee consists of 15 members, representing the 15 participants in the All-Requirements Power Supply Project (ARP). The Executive Committee has the responsibility of approving the ARP budget and agency general budget, approving and financing ARP projects, approving ARP expenditures and contracts, and governs and manages the business and affairs of the ARP. At its annual meeting, the Executive Committee elects a Chairperson and Vice Chairperson.

1.2 All-Requirements Power Supply Project

FMPA developed the All-Requirements Power Supply Project to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the needs of the ARP members. Fifteen FMPA member municipals form the ARP. The locations of the ARP members are shown in Figure 1-1.

Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP members. The ARP began delivering capacity and energy to these original five participants in 1986. The remaining ten members joined as follows:

- 1991 – The City of Clewiston;
- 1997- The Cities of Vero Beach and Starke;
- 1998 – Fort Pierce Utilities Authority (FPUA) and the City of Key West;
- 2000 - The City of Fort Meade, the Town of Havana, and the City of Newberry; and
- 2002 – Kissimmee Utility Authority (KUA) and the City of Lake Worth.

The City of Vero Beach has provided notice to FMPA to exercise their right to modify their ARP full requirements membership beginning January 1, 2010.

Figure 1-1
ARP Member Cities

ARP members are required to purchase all of their capacity and energy from the ARP. ARP members that own generating capacity are required to sell the electric capacity and energy of their generating resources to FMPA. In exchange for the sale of their electric capacity and energy, the owners receive capacity and energy (C&E) payments. All ARP members are supplied 100 percent of their ARP capacity and energy requirements from FMPA at the average capacity and energy rate of the ARP.

Following is a brief description of each of the ARP member cities. The information provided is based on the Florida Municipal Electric Association's 2007 membership directory (www.publicpower.com) and additional information obtained during 2007.

Bushnell

The City of Bushnell is located in central Florida in Sumter County. The City joined the ARP in May 1986. Vince Ruano is the City Manager and Bruce Hickle is the Director of Utilities. The City's service area is approximately 1.4 square miles. For more information about the City of Bushnell, please visit www.cityofbushnellfl.com.

Clewiston

The City of Clewiston is located in southern Florida in Hendry County. The City joined the ARP in May 1991. Kevin McCarthy is the Utilities Director. The City's service area is approximately

5 square miles. For more information about the City of Clewiston, please visit www.clewiston-fl.gov.

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City joined the ARP in February 2000. Fred Hilliard is the City Manager. The City's service area is approximately 5 square miles. FMPA serves capacity and energy requirements for the City via the full requirements agreement currently in place with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the City from the ARP's portfolio of power supply resources. For more information about the City of Fort Meade, please visit www.cityoffortmeade.com.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. FPUA joined the ARP in January 1998. William Theiss is the Director of Utilities and Thomas W. Richards is Director of Electric & Gas Systems. FPUA's service area is approximately 35 square miles. For more information about Fort Pierce Utilities Authority, please visit www.fpua.com.

Green Cove Springs

The City of Green Cove Springs is located in northeast Florida in Clay County. The City joined the ARP in May 1986. Gregg Griffin is the Director of Electric Utility. The City's service area is approximately 25 square miles. For more information about the City of Green Cove Springs, please visit www.greencovesprings.com.

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. The Town joined the ARP in July 2000. Howard McKinnon is the Town Manager. The Town's service area is approximately 5 square miles. For more information about the Town of Havana, please visit www.havanaflorida.com.

Jacksonville Beach

The City of Jacksonville Beach's electric department, more commonly known as Beaches Energy Services (Beaches), is located in northeast Florida and serves customers in Duval and St. Johns Counties. Beaches joined the ARP in May 1986. George D. Forbes is the City Manager and Don Ouchley is the Utilities Director. Beaches' service area is approximately 45 square miles. For more information about Beaches, please visit www.beachesenergy.com.

Utility Board, City of Key West

The Utility Board of the City of Key West, also known as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998. Lou Hernandez is Chairman of the Utility Board and Lynne Tejeda is the General Manager and CEO. KEYS' service area is approximately 45 square miles. For more information about Keys Energy Services, please visit www.keysenergy.com.

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. Kissimmee Utility Authority (KUA) joined the ARP in October 2002. James C. Welsh is the President & General Manager, CEO, and Larry Mattern is Vice President of Power Supply. KUA's service area is approximately 85 square miles. For more information about Kissimmee Utility Authority, please visit www.kua.com.

Lake Worth

Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002. Laura Hannah is the Assistant City Manager/Interim City Manager. Lake Worth's service area is approximately 12.5 square miles. For more information about the City of Lake Worth, please visit www.lakeworth.org.

Leesburg

The City of Leesburg is located in central Florida in Lake County. The City joined the ARP in May 1986. Jay Evans is the City Manager and Paul Kalv is the Director of Electric Department. The City's service area is approximately 50 square miles. For more information about the City of Leesburg, please visit www.leesburgflorida.gov.

Newberry

The City of Newberry is located in north central Florida in Alachua County. The City joined the ARP in December 2000. Blaine Suggs is the Utilities and Public Works Director. The City's service area is approximately 6 square miles. For more information about the City of Newberry, please visit www.cityofnewberryfl.com.

Ocala

The City of Ocala is located in central Florida in Marion County. The City joined the ARP in May 1986. Paul Nugent is the City Manager, and Rebecca Mattey is the Director of Electric

Utility. The City's service area is approximately 161 square miles. For more information about the City of Ocala, please visit www.ocalafl.org.

Starke

Starke is located in north Florida in Bradford County. The City joined the ARP in October 1997. Ricky Thompson is the City Operations Manager. The City's service area is approximately 6.5 square miles. For more information about the City of Starke, please visit www.cityofstarke.org.

Vero Beach

The City of Vero Beach is located on Florida's east coast in Indian River County. Vero Beach joined the ARP in June 1997. James M. Gabbard is the City Manager. The City's service area is approximately 40 square miles.

On December 9, 2004, the City of Vero Beach sent FMPA its "Notice of Establishment of Contract Rate of Delivery." The effective date of the notice is January 1, 2010. The effect of the notice is that the ARP will no longer utilize the City's generating resources, and the ARP will commence serving Vero Beach on a partial requirements basis. The amount of the partial requirements will be determined in 2009. For more information about the City of Vero Beach, please visit www.covb.org.

1.3 FMPA Other Generation Projects

In addition to the ARP, FMPA has four other power supply projects as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit. The 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, with the following entitlements as shown in Table 1-1.

Table 1-1
St. Lucie Project Participants

City	% Entitlement	City	% Entitlement
Alachua	0.431	Clewiston	2.202
Fort Meade	0.336	Fort Pierce	15.206
Green Cove Springs	1.757	Homestead	8.269
Jacksonville Beach	7.329	Kissimmee	9.405
Lake Worth	24.870	Leesburg	2.326
Moore Haven	0.384	Newberry	0.184
New Smyrna Beach	9.884	Starke	2.215
Vero Beach	15.202		

Stanton Project

On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit No. 1. Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of FMPA's members are participants in the Stanton Project with entitlements as shown in Table 1-2.

Table 1-2
Stanton Project Participants

City	% Entitlement	City	% Entitlement
Fort Pierce	24.390	Homestead	12.195
Kissimmee	12.195	Lake Worth	16.260
Starke	2.439	Vero Beach	32.521

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 FMPA's members are participants in the Tri-City Project with the following entitlements as shown in Table 1-3.

Table 1-3
Tri-City Project Participants

City	% Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

Stanton II Project

On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2367 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 FMPA's members are participants in the Stanton II Project with the following entitlements as shown in Table 1-4.

Table 1-4
Stanton II Project Participants

City	% Entitlement	City	% Entitlement
Fort Pierce	16.4880	Homestead	8.2443
Key West	9.8932	Kissimmee	32.9774
St. Cloud	14.6711	Starke	1.2366
Vero Beach	16.4887		

1.4 Summary of Projects

Table 1-5 provides a summary of FMPA member project participation as of January 1, 2008.

Table 1-5
Summary of FMPA Power Supply Project Participants

Agency Member [1]	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X			X	
Ft. Pierce Utilities Authority	X	X	X	X	X
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 Lake Worth	X	X		X	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X

[1] Other FMPA non-project participants include the City of Bartow, the City of Blountstown, the City of Chattahoochee, Gainesville Regional Utilities, City of Lakeland Electric & Water, the City of Mt. Dora, Orlando Utilities Commission, the City of Quincy, the City of Wauchula, and the City of Williston.

Florida Municipal Power Agency

Section 2.0

Description of Existing Facilities

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Section 2 Description of Existing Facilities

2.1 ARP Supply-Side Resources

The ARP supply-side resources consist of a diversified mix of generation ownership, purchase power, and fuel supply. The supply side resources for the ARP for the 2008 summer season are shown by ownership capacity in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2008

Resource Category	Summer Capacity (MW)
1) Nuclear	84
2) ARP Ownership	
Existing	569
New	296
Sub Total ARP Ownership	865
3) Member Ownership	
KES	38
KUA	291
Lake Worth	90
Vero Beach	138
Sub Total Member Ownership	557
4) Purchase Power	410
Total 2008 ARP Resources	1,916

The resource categories shown in Table 2-1 are described in more detail below.

1) **Nuclear Generation:** 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, which provides 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 considered in the capacity planning for the ARP.

2) **ARP Owned Generation:** This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation. Such ARP ownership capacity includes the Stanton Energy Center (including the Stanton, Tri-City, and Stanton II projects, as well as Stanton A), Indian River, Cane Island, and Stock Island units.

3) **Member Owned 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.

4) **Purchase Power Generation:** This category 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. Purchase power generation includes capacity and energy received from other suppliers such as Progress Energy Florida (PEF), Florida Power and Light (FPL), Calpine, and Southern Company.

Information regarding existing ARP generating facilities as of December 31, 2007, can be found in Schedule 1 at the end of this section.

2.2 ARP Transmission System

The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 KV to 500 KV. Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia/Alabama interface. Florida Power and Light (FPL), Progress Energy Florida (PEF), JEA and the City of Tallahassee own the transmission tie lines at the Florida/Georgia/Alabama interface. ARP members' transmission lines are interconnected with transmission facilities owned by FPL, PEF, Orlando Utilities Commission (OUC), JEA, Seminole Electric Cooperative, Florida Keys Electric Cooperative Association (FKEC), and Tampa Electric Company (TECO).

Capacity and energy (C&E) resources for the ARP are transmitted to the ARP members utilizing the transmission systems of FPL, PEF, TECO, and OUC. C&E resources for the Cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, Lake Worth, Starke and Vero Beach are delivered by FPL's transmission system. C&E resources for the Cities of Ocala, Leesburg, Bushnell, Newberry, and Havana are delivered by the PEF transmission system. C&E resources for KUA are delivered by the transmission systems of FPL, PEF and

OUC. C&E resources for the City of Fort Meade are delivered by the PEF and TECO transmission systems.

2.2.1 Member Transmission Systems

Fort Pierce Utility Authority

Fort Pierce Utility Authority (FPUA) is a municipally owned utility operating electric, water, wastewater, and natural gas utilities. The electric utility owns an internal, looped, 69kV transmission system for system load and a 119 MW local power generating plant. FPUA plans to retire its generating plant in 2008. There are two interconnections with other utilities, both at 138 kV. The FPUA's Hartman Substation interconnects to FPL's Midway and Emerson Substations. The second interconnection is from the FPUA's Garden City (#2) Substation to County Line Substation No. 20 by a 7.5 mile, single circuit 138 kV line. FPUA and the City of Vero Beach jointly own County Line Substation, the 138 kV line connecting to Emerson Substation, and some parts of the tie between the two cities.

Keys Energy Services

The Utility Board of the City of Key West (KEYS) owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy south of Florida Keys electric Cooperative's (FKEC) Marathon Substation to the City of Key West. KEYS and FKEC jointly own a 64 mile long 138 kV transmission tie line from FKEC's Marathon Substation that interconnects to FPL's Florida City Substation at the Dade/Monroe County Line. In addition, a second interconnection with FPL was completed in 1995, which consists of a jointly owned 21 mile 138 kV tie line between the FKEC's Tavernier and Florida City Substations at the Dade/Monroe County line and is independently operated by FKEC. KEYS owns a 49.2 mile long 138 kV radial transmission line from Marathon Substation to KEYS' Stock Island Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has five 69 kV and four 138 kV substations which supply power at 13.8 kV and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution line.

City of Lake Worth Utilities

The City of Lake Worth Utilities (LWU) owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy in and around the City of Lake Worth. The total generating capability, located at the Tom G. Smith power generating plant is rated at approximately 98 MW. LWU has one 138 kV interconnection with FPL at the LWU owned Hypoluxo Switching Station. A 3-mile radial 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4-mile radial 138 kV transmission line connects the Main Plant Substation to LWU's Canal Substation. Two 138/26 kV autotransformers are located at the Main Plant, and one 138/26 kV autotransformer is located at Canal Substation. The utility owns an internal 26 kV sub-transmission system to serve system load.

Kissimmee Utility Authority

KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines. KUA serves a total area of approximately 85 square miles. KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO and the City of St. Cloud. KUA owns 24.6 circuit miles of 230 kV and 52.8 circuit miles of 69 kV transmission lines. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. Electric capacity and energy supplied from KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to ten distribution substations. KUA has direct transmission interconnections with: (1) PEF at PEF's 230 kV Intercession City Substation, 69 kV Lake Bryan Substation, and 69 kV Meadow Wood South Substation; (2) OUC at OUC's 230 kV Taft Substation and TECO / OUC's 230 kV Osceola Substation from Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

City of Ocala Electric Utility

Ocala Electric Utility (OEU) owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles radial 230 kV and 48 miles 69 kV transmission loop and 18 distribution substations delivering power at 12.47 kV. The distribution system consists of 773 miles of overhead lines and 302 miles of underground lines.

OEU's 230kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs North Switching Station. OEU's Dearmin Substation ties at PEF's Silver Springs Switching Station and OEU's Ergle Substation ties at SECI's Silver Springs North Switching Station. OEU also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OEU owns a 13 mile radial 230 kV transmission line from Ergle Substation to Shaw Substation. OEU has completed and placed in service a second 230 kV tie by rerouting the existing Shaw to Ergle 230 kV line from Shaw Substation to a direct radial connecting to SECI's Silver Springs North Switching Station.

City of Vero Beach

The City of Vero Beach (CVB) has a municipally owned electric utility. The utility owns an internal, looped, 69 kV transmission system for system load and a 155 MW local power generating plant. CVB has two 138 kV interconnections with FPL and one with FPUA. CVB's interconnection with FPL is at CVB's West Substation No. 7. CVB also has a second FPL interconnection from County Line Substation No. 20. County Line Substation No. 20 is connected by two separate, single circuit, 138 kV transmission lines to FPL's Emerson 230/138 kV substation and FPUA's Garden City (No. 2) Substation. CVB & FPUA jointly own County Line Substation No. 20, the connecting lines to FPL's Emerson Station, and some part of the tie between the two municipal utilities.

2.2.2 ARP Transmission Agreements

OUC provides transmission service for delivery of power and energy from FMPA's ownership in Stanton Unit No. 1, Stanton Unit No. 2, Stanton A combined cycle (CC), and the Indian River combustion turbine (CT) units to the FPL and PEF interconnections for subsequent delivery to the ARP. Rates for such transmission wheeling service are based upon OUC's costs of providing such transmission wheeling service and under terms and conditions of the OUC-FMPA Firm Transmission Service contracts for the ARP.

FMPA also has contracts with PEF and FPL to transmit the various ARP resources over the transmission systems of each of these two utilities. The Network Service Agreement with FPL was executed in March 1996 and was subsequently amended to both conform to FERC's Pro forma Tariff and to add additional members to the ARP. The FPL agreement provides for network transmission service for the ARP member cities located in FPL's service territory. To provide transmission-wheeling service for ARP member cities located in PEF's service territory, FMPA operates under an existing agreement with PEF, which was executed in April 1985 and provides for network type transmission services.

Schedule 1
ARP Existing Generating Resources as of December 31, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Nuclear Capacity												
Crystal River	3	Citrus	NP	UR	-	TK	-	03/77	NA	891	24	25
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	60	61
Total Nuclear Capacity											84	86
ARP-Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	102	103
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	101	101
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	14	18
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	14	18
Indian River	CT C	Brevard	GT	NG	DFO	PL	TK	08/92	NA	112	22	26
Indian River	CT D	Brevard	GT	NG	DFO	PL	TK	10/92	NA	112	22	26
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	17
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	53	56
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	126	131
Stock Island	CT2	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	15
Stock Island	CT3	Monroe	GT	DFO	-	WA	-	06/99	NA	21	15	15
Stock Island	GT4	Monroe	GT	DFO	-	WA	-	06/06	NA	61	45	45
Total ARP-Owned Generation											569	595
Member-Owned Generation												
Vero Beach												
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	NA	13	11	12
Municipal Plant	2	Indian River	CA	NG	RFO	PL	TK	08/64	NA	13	12	11
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	09/71	NA	33	32	33
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	08/76	NA	56	51	53
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	NA	40	32	35
Sub Total Vero Beach											138	144
Fort Pierce Utilities Authority												
H.D. King	5	St. Lucie	CA	WH	-	-	-	01/53	05/08	8	0	8
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	01/64	05/08	32	0	30
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	05/76	01/08	50	0	0
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	05/90	05/08	23	0	23
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	0	3
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	0	3
Sub Total Fort Pierce											0	66

Schedule 1 (Continued)
ARP Existing Generating Resources as of December 31, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Kissimmee Utility Authority												
Hansel Plant	21	Osceola	CT	NG	-	PL	TK	02/83	12/11	38	29	35
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	12/11	8	8	5
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	12/11	8	8	5
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	17
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	53	56
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	126	131
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	21	21
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	4	6
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	4	6
Sub Total KUA											291	304
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	12/76	05/11	31	26	27
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	03/78	05/11	20	21	21
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	12/65	05/11	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	12/65	05/11	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	12/65	05/11	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	12/65	05/11	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	12/65	05/11	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	05/11	27	26	27
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	03/78	05/11	10	8	9
Sub Total Lake Worth											90	94
Keys Energy Services												
Stock Island	CT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	18	18
Stock Island HSD	IC1	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island HSD	IC2	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island HSD	IC3	Monroe	IC	DFO	-	WA	-	01/65	NA	2	2	2
Stock Island MSD	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8	8
Stock Island MSD	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8	8
Sub Total Keys											38	38
Total Member-Owned Generation											557	647
Total Generation Resources											1,210	1,327

Florida Municipal Power Agency

Section 3.0

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

Community Power + Statewide Strength

Section 3 Forecast of Demand and Energy for the All-Requirements Power Supply Project

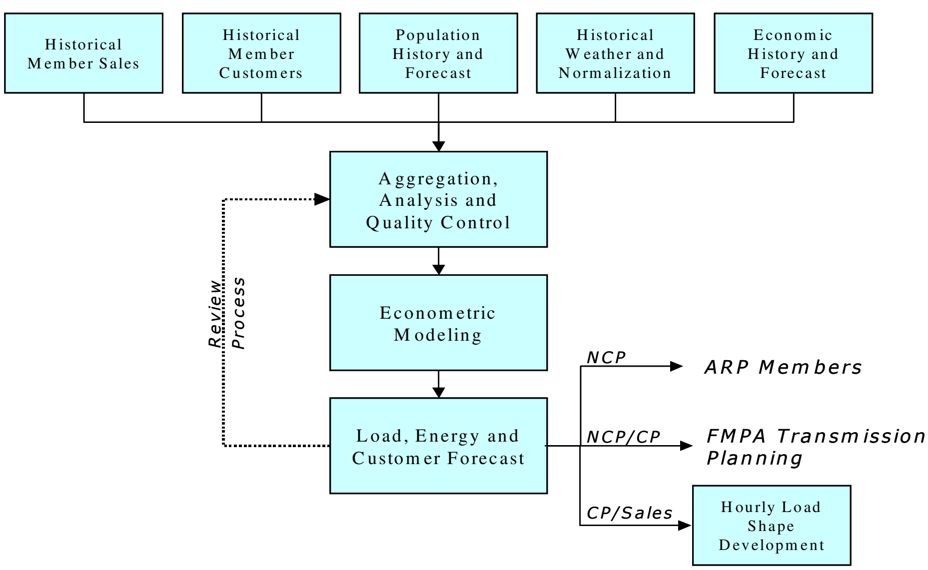
3.1 Introduction

Under the ARP structure, FMPA agrees to meet all of the ARP members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's electrical power demand and energy requirements on an individual basis and integrates the results into a forecast for the entire ARP. The following discussion summarizes the load forecasting process and the results of the load forecast contained in this Ten-Year Site Plan.

3.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP members. The forecast process includes existing ARP member cities that FMPA currently supplies and ARP members that FMPA is scheduled to begin supplying in the future. Forecasts are prepared on an individual member basis and are then aggregated into projections of the total ARP demand and energy requirements. Figure 3-1 below identifies FMPA's load forecast process.

Figure 3-1
Load Forecast Process



In addition to the Base Case load and energy forecast, FMPA has prepared high and low case forecasts, which are intended to capture the majority of the uncertainty in certain driving variables, for each of the ARP members. The high and low load forecast scenarios are considered in FMPA's resource planning process. In this way, power supply plans are tested for their robustness under varying future load conditions.

3.3 2007 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2007 through 2026. The Forecast was 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 were provided by Economy.com, a nationally recognized provider of such data. The Forecast also relied on information regarding local economic and demographic issues specific to each ARP member. The Forecast reflects the City of Vero Beach Notice of Establishment of Contract Rate of Delivery (CROD). The Forecast was performed assuming that Vero Beach's CROD becomes effective on January 1, 2010; however, the results of the Forecast do not currently include the partial requirements load referred to in Section 1.2 of this document that may be served by FMPA beginning January 1, 2010. The results of the Base Case forecast are discussed in Section 3.6.1.

In addition to the Base Case forecast, FMPA has prepared high and low forecasts to capture the uncertainty of weather. The methodology and results of the high (Severe) and low (Mild) weather cases are discussed in Section 3.6.2.

3.4 Methodology

The forecast of peak demand and net energy for load to be supplied from the ARP relies on an econometric forecast of each ARP member's retail sales, combined with various assumptions regarding loss, load, and coincidence factors, generally based on the recent historical values for such factors, which are then summed across the ARP members. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience.

In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures. Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. The ability of a model to explain historical variation is often referred to as "goodness-of-fit." These historical relationships are generally assumed to continue into the future, barring any specific information or assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in load rather than simply an extrapolation of history. As a result of this approach, utilities are more likely to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships which affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving decisions. The Severe and Mild Cases are examples of this capability.

Forecasts of monthly sales were prepared by rate classification for each ARP member. In some cases, rate classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater stability is provided in the historical period upon which statistical relationships are based.

3.4.1 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. The 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 ARP members and the number of households in each ARP member's county.

The non-residential electricity sales models reflect that energy sales are best explained by: (i) real retail sales, total personal income, or gross domestic product (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. For the majority of models, total personal income was selected as the measure of economic activity, because it performed better by certain statistical measures than other variables and is measured historically with more accuracy at the local level. For the industrial class, GDP was more often the long-term driving variable, except in cases where the forecast was based on an assumption to address a single, large customer (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.

3.4.2 Projection of NEL and Peak Demand

The forecast of sales for each rate classification described above were summed to equal the total retail sales of each ARP member. An assumed loss factor, typically based on a 5-year average of historical loss factors, was then applied to the total sales to derive monthly NEL. To the extent historical loss factors were deemed anomalous, they were excluded from these averages.

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted net energy for load on a total member system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1997-2006 (i.e., a 10-year average).

Monthly peak demand was 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 occur 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 ARP member groups, and the transmission providers were derived from monthly coincidence factors averaged generally over a 5-year period (2002-2006). The historical coincidence factors are based on historical coincident peak demand data that is maintained by FMPA. Similarly, the timing of the total ARP and ARP member group peaks was determined from an appropriate summation of the hourly load data.

3.5 Data Sources

3.5.1 Historical Member Retail Sales Data

Data was generally available and analyzed over January 1992 through March 2007 (Study Period). Data included historical customer counts, sales, and revenues by rate classification for each of the members. However, for a small part of the Study Period, only total revenues were available.

3.5.2 Weather Data

Historical weather data was provided by the National Climatic Data Center (a subsidiary of the National Oceanic and Atmospheric Administration) (NCDC), which was generally used to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was obtained, were selected by their quality and proximity to the ARP members. 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 three cases (Beaches Energy Services, Fort Pierce, and Vero Beach), however, weather data from a "cooperative" weather station, which was closer than the closest first-order station, appeared to more accurately reflect the weather conditions that affect the ARP members' loads, 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 a base temperature, 65 degrees Fahrenheit. To the extent the average daily temperature exceeds 65 degrees Fahrenheit, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDD result from average daily temperatures which are below 65 degrees Fahrenheit. Heating and cooling degree days are then summed over the period of interest, in this case, months. The majority of this monthly data was obtained directly from the NCDC rather than calculated from daily data.

Normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions from 1971 through 2000, as reported by the NCDC.

3.5.3 Economic Data

Economy.com, a nationally recognized provider of economic data, provided both historical and projected economic and demographic data for each of the 16 counties in which the Members' service territories reside (the service territory of Beaches Energy Services includes portions of both Duval and St. Johns Counties). This data includes county population, households, employment, personal income, retail sales, and gross domestic product. Although all of the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales.

3.5.4 Real Electricity Price Data

The real price of electricity was derived from a twelve month moving average of real average revenue. To the extent average revenue data specific to a certain rate classification was unavailable, it was assumed to follow the trend of total average revenue of the utility. Projected electricity prices were assumed to increase at the rate of inflation. Consequently, the real price was projected to be essentially constant.

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the net energy for load to be supplied by the ARP is expected to grow at an annual average growth rate of 2.5% from 2007-2016, and then at a lower growth rate of 2.1% from 2017-2026. The Base Case 2008 ARP forecast winter peak demand is 1,409 MW, forecast summer peak demand is 1,525 MW, and forecast annual NEL is 7,558 GWh.

3.6.2 Weather-Related Uncertainty of the Forecast

While a forecast that is derived from projections of driving variables that are obtained from reputable sources provides a sound basis for planning, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed or provided, the actual member load can be expected to vary from the forecast. For various purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

In addition to the Base Case forecast, which relies on normal weather conditions, FMPA has developed high and low forecasts, referred to herein as the Severe and Mild weather cases, intended to capture the volatility resulting from weather variations in the summer and winter seasons equivalent to 90 percent of potential occurrences. Accordingly, load variations due to weather should be outside the resulting "band" between the Mild and Severe weather cases less than 1 out of 10 years. For this purpose, the summer and winter seasons were assumed to encompass June through September and December through February, respectively.

The potential weather variability was developed using weather data specific to each weather station generally over the period 1971-2006. These weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, although this is less likely to happen than severe conditions in one season or the other. Accordingly, it should be recognized that annual NEL may be somewhat less volatile than the annual NEL variation shown herein. Conversely, NEL in any particular month may be *more* volatile than shown herein. Finally, because the forecast methodology derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand are effectively assumed to have the same weather-related volatility as annual NEL.

The weather scenarios result in bands of uncertainty around the Base Case that are essentially constant through time, so that the projected growth rate is the same as the Base Case. The differential between the Severe Case and Base Case is somewhat larger than between the Mild Case and Base Case as a result of a somewhat non-linear response of load to weather.

3.7 Load Forecast Schedules

Schedules 2.1 through 2.3 and 3.1 through 3.3 present the Base Case load forecast. Schedules 3.1a through 3.3a present the high, or Severe weather case, and Schedules 3.1b through 3.3b present the low, or Mild weather case. Schedule 4 presents the Base Case monthly load forecast.

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 [1]	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1998	NA	NA	1,977	143,049	13,822	1,593	26,001	61,276
1999	NA	NA	1,980	151,885	13,035	1,652	27,774	59,465
2000	NA	NA	2,066	154,942	13,337	1,721	28,404	60,595
2001	NA	NA	2,105	156,876	13,421	1,750	28,929	60,492
2002	NA	NA	2,426	174,365	13,913	1,996	32,344	61,724
2003	NA	NA	3,180	227,851	13,955	2,603	42,132	61,791
2004	NA	NA	3,170	234,698	13,508	2,630	42,914	61,274
2005	NA	NA	3,269	238,050	13,733	2,675	43,805	61,055
2006	NA	NA	3,293	244,195	13,487	2,692	43,968	61,231
2007	NA	NA	3,327	249,731	13,322	2,689	45,092	59,635
2008	NA	NA	3,478	254,537	13,664	2,759	46,341	59,531
2009	NA	NA	3,592	262,004	13,709	2,846	47,343	60,123
2010	NA	NA	3,290	237,875	13,831	2,519	42,404	59,397
2011	NA	NA	3,371	242,841	13,883	2,564	43,116	59,471
2012	NA	NA	3,452	247,946	13,924	2,609	43,827	59,523
2013	NA	NA	3,537	253,253	13,966	2,656	44,570	59,600
2014	NA	NA	3,625	258,657	14,014	2,706	45,360	59,650
2015	NA	NA	3,716	264,205	14,063	2,755	46,177	59,672
2016	NA	NA	3,809	269,872	14,113	2,805	46,993	59,690
2017	NA	NA	3,903	275,582	14,162	2,854	47,809	59,704

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

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			Railroads and Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Customers
Year [1]	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	GWh	GWh	GWh
1998	643	972	661,427	0	27	42	4,283
1999	678	1,031	657,495	0	27	45	4,381
2000	695	1,078	644,762	0	28	48	4,558
2001	692	1,104	626,720	0	31	49	4,627
2002	718	1,132	634,523	0	41	46	5,228
2003	708	1,151	615,521	0	52	46	6,590
2004	700	1,137	615,842	0	52	56	6,608
2005	728	1,170	621,905	0	54	45	6,769
2006	740	1,219	607,328	0	56	46	6,828
2007	781	1,270	614,906	0	62	44	6,904
2008	795	1,319	603,219	0	65	44	7,141
2009	814	1,365	596,404	0	66	45	7,363
2010	834	1,410	591,470	0	64	46	6,752
2011	856	1,457	587,539	0	65	46	6,903
2012	878	1,507	582,770	0	67	47	7,053
2013	902	1,561	577,831	0	68	48	7,211
2014	927	1,617	573,075	0	70	49	7,376
2015	952	1,676	568,361	0	71	50	7,544
2016	978	1,738	563,089	0	73	51	7,716
2017	1,004	1,801	557,417	0	74	52	7,887

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

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 [1]	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1998	0	247	4,530	0	170,022
1999	0	276	4,657	0	180,690
2000	0	279	4,838	0	184,424
2001	0	250	4,877	0	186,909
2002	0	305	5,532	0	207,841
2003	0	418	7,008	0	271,134
2004	0	392	7,000	0	278,749
2005	0	375	7,145	0	283,025
2006	0	383	7,211	0	289,382
2007	0	389	7,293	0	296,093
2008	0	417	7,558	0	302,196
2009	0	432	7,795	0	310,712
2010	0	401	7,153	0	281,690
2011	0	409	7,312	0	287,415
2012	0	418	7,471	0	293,281
2013	0	427	7,638	0	299,384
2014	0	437	7,812	0	305,633
2015	0	446	7,991	0	312,058
2016	0	456	8,172	0	318,602
2017	0	466	8,354	0	325,192

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
1998	947	0	0	0	0	0	0	0	947
1999	982	0	0	0	0	0	0	0	982
2000	972	0	0	0	0	0	0	0	972
2001	962	0	0	0	0	0	0	0	962
2002	1,201	0	0	0	0	0	0	0	1,201
2003	1,343	0	0	0	0	0	0	0	1,343
2004	1,416	0	0	0	0	0	0	0	1,416
2005	1,524	0	0	0	0	0	0	0	1,524
2006	1,478	0	0	0	0	0	0	0	1,478
2007	1,469	0	0	0	0	0	0	0	1,469
2008	1,525	0	0	0	0	0	0	0	1,525
2009	1,574	0	0	0	0	0	0	0	1,574
2010	1,446	0	0	0	0	0	0	0	1,446
2011	1,478	0	0	0	0	0	0	0	1,478
2012	1,511	0	0	0	0	0	0	0	1,511
2013	1,545	0	0	0	0	0	0	0	1,545
2014	1,580	0	0	0	0	0	0	0	1,580
2015	1,617	0	0	0	0	0	0	0	1,617
2016	1,654	0	0	0	0	0	0	0	1,654
2017	1,691	0	0	0	0	0	0	0	1,691

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
1997/98	675	0	0	0	0	0	0	0	675
1998/99	926	0	0	0	0	0	0	0	926
1999/00	947	0	0	0	0	0	0	0	947
2000/01	1,008	0	0	0	0	0	0	0	1,008
2001/02	1,008	0	0	0	0	0	0	0	1,008
2002/03	1,473	0	0	0	0	0	0	0	1,473
2003/04	1,194	0	0	0	0	0	0	0	1,194
2004/05	1,340	0	0	0	0	0	0	0	1,340
2005/06	1,401	0	0	0	0	0	0	0	1,401
2006/07	1,202	0	0	0	0	0	0	0	1,202
2007/08	1,409	0	0	0	0	0	0	0	1,409
2008/09	1,454	0	0	0	0	0	0	0	1,454
2009/10	1,304	0	0	0	0	0	0	0	1,304
2010/11	1,334	0	0	0	0	0	0	0	1,334
2011/12	1,364	0	0	0	0	0	0	0	1,364
2012/13	1,394	0	0	0	0	0	0	0	1,394
2013/14	1,427	0	0	0	0	0	0	0	1,427
2014/15	1,460	0	0	0	0	0	0	0	1,460
2015/16	1,494	0	0	0	0	0	0	0	1,494
2016/17	1,528	0	0	0	0	0	0	0	1,528

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year [1]	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1998	4,283	0	0	4,283	0	247	4,530	55%
1999	4,381	0	0	4,381	0	276	4,657	54%
2000	4,558	0	0	4,558	0	279	4,838	57%
2001	4,627	0	0	4,627	0	250	4,877	55%
2002	5,228	0	0	5,228	0	305	5,532	53%
2003	6,590	0	0	6,590	0	418	7,008	54%
2004	6,608	0	0	6,608	0	392	7,000	56%
2005	6,769	0	0	6,769	0	375	7,145	54%
2006	6,828	0	0	6,828	0	383	7,211	56%
2007	6,904	0	0	6,904	0	389	7,293	57%
2008	7,141	0	0	7,141	0	417	7,558	57%
2009	7,363	0	0	7,363	0	432	7,795	57%
2010	6,752	0	0	6,752	0	401	7,153	56%
2011	6,903	0	0	6,903	0	409	7,312	56%
2012	7,053	0	0	7,053	0	418	7,471	56%
2013	7,211	0	0	7,211	0	427	7,638	56%
2014	7,376	0	0	7,376	0	437	7,812	56%
2015	7,544	0	0	7,544	0	446	7,991	56%
2016	7,716	0	0	7,716	0	456	8,172	56%
2017	7,887	0	0	7,887	0	466	8,354	56%

[1] Amounts shown for 1998 through 2006 represent historical values. Amounts shown for 2007 through 2017 represent forecast values.

Schedule 3.1a
Forecast of Summer Peak Demand (MW) – High Case
All-Requirements Project [1]

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2008	1,591	0	0	0	0	0	0	0	1,591
2009	1,642	0	0	0	0	0	0	0	1,642
2010	1,509	0	0	0	0	0	0	0	1,509
2011	1,543	0	0	0	0	0	0	0	1,543
2012	1,577	0	0	0	0	0	0	0	1,577
2013	1,613	0	0	0	0	0	0	0	1,613
2014	1,650	0	0	0	0	0	0	0	1,650
2015	1,688	0	0	0	0	0	0	0	1,688
2016	1,727	0	0	0	0	0	0	0	1,727
2017	1,766	0	0	0	0	0	0	0	1,766

[1] Values represent predicted summer peak demand under severe weather conditions.

Schedule 3.2a
Forecast of Winter Peak Demand (MW) – High Case
All-Requirements Project [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
2007/08	1,468	0	0	0	0	0	0	0	1,468
2008/09	1,515	0	0	0	0	0	0	0	1,515
2009/10	1,360	0	0	0	0	0	0	0	1,360
2010/11	1,392	0	0	0	0	0	0	0	1,392
2011/12	1,423	0	0	0	0	0	0	0	1,423
2012/13	1,455	0	0	0	0	0	0	0	1,455
2013/14	1,488	0	0	0	0	0	0	0	1,488
2014/15	1,523	0	0	0	0	0	0	0	1,523
2015/16	1,558	0	0	0	0	0	0	0	1,558
2016/17	1,594	0	0	0	0	0	0	0	1,594

[1] Values represent predicted winter peak demand under severe weather conditions.

Schedule 3.3a
Forecast of Annual Net Energy for Load (GWh) – High Case
All-Requirements Project [1]

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2008	7,449	0	0	7,449	0	429	7,878	56%
2009	7,682	0	0	7,682	0	444	8,126	57%
2010	7,050	0	0	7,050	0	412	7,462	56%
2011	7,208	0	0	7,208	0	421	7,629	56%
2012	7,365	0	0	7,365	0	430	7,795	56%
2013	7,530	0	0	7,530	0	439	7,970	56%
2014	7,702	0	0	7,702	0	449	8,151	56%
2015	7,878	0	0	7,878	0	459	8,338	56%
2016	8,057	0	0	8,057	0	470	8,527	56%
2017	8,237	0	0	8,237	0	480	8,717	56%

[1] Values represent predicted net energy for load under severe weather conditions.

Schedule 3.1b
Forecast of Summer Peak Demand (MW) – Low Case
All-Requirements Project [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
2008	1,474	0	0	0	0	0	0	0	1,474
2009	1,520	0	0	0	0	0	0	0	1,520
2010	1,396	0	0	0	0	0	0	0	1,396
2011	1,428	0	0	0	0	0	0	0	1,428
2012	1,459	0	0	0	0	0	0	0	1,459
2013	1,492	0	0	0	0	0	0	0	1,492
2014	1,526	0	0	0	0	0	0	0	1,526
2015	1,561	0	0	0	0	0	0	0	1,561
2016	1,597	0	0	0	0	0	0	0	1,597
2017	1,633	0	0	0	0	0	0	0	1,633

[1] Values represent predicted summer peak demand under mild weather conditions.

Schedule 3.2b
Forecast of Winter Peak Demand (MW) – Low Case
All-Requirements Project [1]

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2007/08	1,363	0	0	0	0	0	0	0	1,363
2008/09	1,406	0	0	0	0	0	0	0	1,406
2009/10	1,260	0	0	0	0	0	0	0	1,260
2010/11	1,289	0	0	0	0	0	0	0	1,289
2011/12	1,318	0	0	0	0	0	0	0	1,318
2012/13	1,347	0	0	0	0	0	0	0	1,347
2013/14	1,378	0	0	0	0	0	0	0	1,378
2014/15	1,410	0	0	0	0	0	0	0	1,410
2015/16	1,443	0	0	0	0	0	0	0	1,443
2016/17	1,476	0	0	0	0	0	0	0	1,476

[1] Values represent predicted winter peak demand under mild weather conditions.

Schedule 3.3b
Forecast of Annual Net Energy for Load (GWh) – Low Case
All-Requirements Project [1]

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2008	6,899	0	0	6,899	0	408	7,307	56%
2009	7,113	0	0	7,113	0	423	7,536	57%
2010	6,518	0	0	6,518	0	392	6,910	57%
2011	6,663	0	0	6,663	0	401	7,064	56%
2012	6,808	0	0	6,808	0	409	7,217	56%
2013	6,961	0	0	6,961	0	418	7,379	56%
2014	7,119	0	0	7,119	0	427	7,546	56%
2015	7,282	0	0	7,282	0	437	7,719	56%
2016	7,447	0	0	7,447	0	447	7,893	56%
2017	7,612	0	0	7,612	0	456	8,068	56%

[1] Values represent predicted net energy for load under mild weather conditions.

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 - 2007		Forecast - 2008		Forecast - 2009	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,165	536	1,409	582	1,454	602
February	1,202	491	1,169	530	1,206	548
March	996	524	1,058	568	1,092	586
April	1,127	532	1,209	554	1,248	572
May	1,245	611	1,366	661	1,410	682
June	1,365	672	1,450	689	1,495	711
July	1,465	737	1,525	770	1,574	794
August	1,521	793	1,524	789	1,572	813
September	1,416	685	1,433	694	1,478	716
October	1,295	652	1,332	627	1,373	646
November	1,026	492	1,106	531	1,139	547
December	958	520	1,162	561	1,199	578

Florida Municipal Power Agency

Section 4.0

Renewable Resources and Conservation Programs

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Section 4 Renewable Resources and Conservation Programs

4.1 Introduction

Renewable resources are considered resources that do not require the consumption of additional fossil fuels in order to provide energy. Conservation programs are typically those that reduce the amount of demand or energy being provided to the customer. Both renewable resources and conservation programs are considered "Green Energy" resources. FMPA and its members are reviewing Green Energy programs that may be of benefit to their customers. FMPA's goal for the coming year includes investigating aggressive renewable and conservation efforts in support of proposed regulations regarding greenhouse gas (GHG) reduction and renewable energy. FMPA anticipates developing Green Energy demonstration projects that involve solar photovoltaics, bio-fuels and waste-to-energy.

FMPA is supporting the efforts of the Florida Energy Sustainability Consortium. The consortium, made up of Florida universities together with industry, promotes statewide collaboration to coordinate and unify efforts in research, development, technology commercialization, education, outreach, and technology transfer in energy. FMPA believes the Florida Energy Sustainability Consortium will bring substantial benefits to the Member cities and the communities they serve. FMPA expects the Consortium to help it build consensus and understanding of issues related to the state proposed GHG reduction program. Likewise, FMPA believes that Florida must pull together the best ideas from energy production, emission control, generation efficiency, customer efficiency and renewable production. It is FMPA's understanding that the Florida Energy Sustainability Consortium will not only bring utility representatives together but representatives from state agencies as well as representatives from various other industry sectors.

FMPA is a member of a group of Florida public power utilities, called Florida Municipal Energy Efficiency Coalition (FMEC). This group was formed in August of 2006 to explore new options for efficiency programs that can result in greater energy conservation and savings to customers. Other members of FMEC are GRU, JEA, Lakeland Electric, OUC, Tallahassee, and Florida Municipal Electric Association. The utilities have agreed to develop consistent data and share best practices as they evaluate DSM programs to save energy that are specific to the state of Florida.

FMPA is also a member of the American Public Power Association's Demonstration of Energy-Efficient Developments (DEED) program. Through FMPA's membership in this program, all of FMPA's members are also DEED members. DEED is a research and development program funded by and for public power utilities. Established in 1980, DEED encourages activities that promote energy innovation, improve efficiencies and lower costs of energy to public power customers.

4.2 Renewable Resources

Fuels used by renewable resources for the production of electric energy can include biomass, solar thermal, solar photovoltaic, geothermal energy, wind energy, ocean energy, hydrogen produced from sources other than fossil fuels, and waste heat from commercial or industrial processes. FMPA utilizes renewable energy resources to serve ARP aggregate load requirements.

FMPA currently receives renewable energy from two sources. FMPA purchases as-available power from a cogeneration plant owned and operated by U.S. Sugar Corporation. The U.S. Sugar cogeneration plant is fueled by sugar bagasse, a byproduct of sugar production. U.S. Sugar Corporation uses the bagasse to fuel their generation plants to provide power for their processes. FMPA purchases the excess power produced from these generators. During 2007, FMPA purchased 5,532 MWh of energy from this renewable resource.

The second renewable resource is landfill gas obtained from the Orange County landfill. Stanton Energy Center Units 1 and 2, coal-fired generating units partially owned by FMPA, utilize the landfill gas as a supplemental fuel source. In 2007 the Stanton Energy Center consumed 752,409 MMbtu of landfill gas.

On June 29, 2007 FMPA issued a request for proposals for renewable energy resources. Three viable proposals were received and analyzed. Although all three proposals exceed FMPA’s avoided costs they are being evaluated further for their total energy and greenhouse gas reduction benefit to ARP members.

4.2.1 Solar Photovoltaic

In late 2007, FMPA issued a request for proposals for solar photovoltaic (PV) energy supply with a goal of implementing 10 MW. Twenty-six proposals were received, and eight were selected for in-depth evaluation to be completed in early 2008. If ultimately approved by the ARP, FMPA will explore the feasibility of implementing up to an additional 90 MW of PV systems dependant upon successful implementation and acceptable performance of the initial 10 MW.

4.2.2 Bio-fuels

FMPA is evaluating the feasibility of operating several of its generating units using bio-fuels. General Electric (GE) has reported that initial trials have proven satisfactory operation in several models of generation units. The initial investigation centers at the Stock Island facility in Key West, as all of the units located at Stock Island use fuel oil exclusively as the energy source.

Tests are planned for bio-diesel fuel to be used in three 20 MW GE Frame 5 combustion turbines. Fuel samples are being tested to confirm the fuel's heat rate and contamination. A major technical drawback under evaluation is performing the modifications necessary to store fuel and operate the units. Bio-fuel is a solvent and may react negatively with tank coatings, hoses, valves, and seals. The second major concern is that more fuel must be delivered to the machine to operate the unit for the same power output as conventional fuel.

4.2.3 Landfill Gas

FMPA is following the progress of the permitting and development of a major landfill gas generation facility to determine the feasibility of a long term contract for the electrical output. Landfill gas projects typically range in size between 1 to 10 MW. The prospective facility is planned for a 15 MW combustion turbine and is currently being permitted. FMPA is awaiting an update from the developer and may negotiate with the owner to receive the electric output.

4.2.4 Plasma Arc

FMPA is evaluating a proposal for construction of a solid waste-to-energy facility using plasma arc technology at the St. Lucie County landfill with a target commercial operation date of 2011. The facility would treat and destroy solid waste either currently in or delivered to the landfill and generate synthesis gas (Syngas). The intent would be for FMPA to purchase the Syngas to burn in a combined cycle power plant to be constructed and operated by FMPA. FMPA is working with the developer, GeoPlasma, LLC, on a Letter of Intent.

FMPA's forecast of renewable energy is provided in Schedule 6.1 of Section 5 (Forecast of Facility Requirements).

4.3 Conservation Programs

As a wholesale supplier, FMPA does not directly provide demand side programs to retail customers. Demand side programs are provided to the retail customers by the ARP members. FMPA offers services as needed to assist members in increasing the promotion and use of conservation programs to customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness.

The following is a combined list of some of the conservation programs offered by or being reviewed by FMPA members:

- Energy Audits Program.
- Compact Florescent Light Bulbs.
- LED Traffic Signals.
- Energy Star® Program Participation.
- Demand-Side Management.
- Distributed Generation.
- System Loss Reduction.

A brief description of each conservation program is provided in the following subsections. The exact implementation varies somewhat from member to member and not all programs are offered by all members.

4.3.1 Energy Audits Program

Energy audits are offered to residential, commercial, and industrial customers. The program offers walk-through audits to identify energy savings opportunities. The audits consist of a walk-through Home Energy Survey, with the following materials available upon customer request:

- Electric outlet gaskets.
- Socket protectors.
- Water flow restrictors.
- Electric water heater jacket.
- Low-flow shower heads.

Home Energy Surveys also include information on water heater temperature reduction and the installation of the water heater insulating blanket upon customer request.

As a supplement to the Energy Audits program, some FMPA members offer online energy surveys to their customers. These tools allow customers to enter specific information on their homes and review specific measures that they can implement in their homes to reduce energy consumption. FMPA also assists member cities with their Key Accounts program, which is designed to build and maintain relationships between members and their key customers. FMPA coordinates the relationship between participating members and contractors to provide project-type services such as lighting retrofits, HVAC upgrades, and energy management system services.

4.3.2 Compact Florescent Light Bulbs

Participants in this program give away and promote compact florescent light (CFL) bulbs to their customers.

4.3.3 LED Traffic Signals

Several members have taken on a conservation measure to convert their traffic signals from using incandescent bulbs to bulbs made with light emitting diodes (LED).

4.3.4 Energy Star® Program Participation

FMPA has a partnership agreement with Energy Star®, a government-backed program helping businesses and individuals protect the environment and save energy through end-use products with superior energy efficiency characteristics. Partnering with Energy Star® and working together through FMPA makes it convenient and cost-effective for FMPA's members to bring the benefits of energy efficiency to their hometown utility. The Energy Star® program includes seasonal campaigns, each promoting different conservation themes. Members are provided with promotional materials including newsletter, posters, bill stuffers, and web banners to participate in the campaigns and promote the conservation message to their customers.

4.3.5 Demand-Side Management

In July 2007, FMPA issued a request for proposals for demand side management (DSM) activities. Four proposals were received, and three of the proposals have been short-listed for further evaluation. Discussions and negotiations are proceeding with the proposers to examine the possibility of implementing demand side programs.

4.3.6 Distributed Generation

Distributed Generation (DG) involves the use of small generators with capacities generally ranging between 10 and several thousand kilowatts spread throughout an electric system. Because they are normally located at customer sites, and those customers are generally demand customers, DG serves well as a vehicle for reducing demands during peak periods.

FMPA is investigating the possibility of operating the standby generators of a grocery store chain during peak load periods and system emergencies. By coordinating the dispatch of these standby generators, FMPA can avoid running its most inefficient resources. As standby generators must be exercised regularly, this generates no net increase in greenhouse gases. The benefit of the program to the grocery store chain is that the company is paid an incentive which offsets some of its operating costs.

4.3.7 System Loss Reduction

Losses are an aggregated component of the electric load of ARP member utilities. As losses are controlled and reduced, so is the need for additional electrical generation. Therefore, reducing losses has a positive effect on the reduction of GHG emissions and can reduce or delay the need for additional generating resources to be constructed. FMPA is leading an effort among its members to investigate losses and invest in loss reduction.

Florida Municipal Power Agency

Section 5.0

Forecast of Facilities Requirements

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Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's planning process involves evaluating new generating capacity, along with new purchased power options 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 power options. FMPA normally performs its generation expansion planning on a least-cost basis considering both purchased-power options, as well as options for 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 currently plans for an annual reserve level of approximately 18 percent of the summer peak. 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.

5.2 Planned ARP Generating Facility Requirements

FMPA is planning to add a 296 MW combined cycle unit at the Treasure Coast Energy Center site in May 2008, an additional 296 MW combined cycle unit at the Cane Island Power Park (CIPP) in 2011, 86 MW of combustion turbine capacity in 2012, 149 MW of combustion turbine capacity in 2013, and an additional 86 MW of combustion turbine capacity in 2015. These resources are described in additional detail below.

- **Treasure Coast Energy Center (TCEC):** FMPA is constructing a 296 MW combined cycle unit at the Treasure Coast Energy Center site in Fort Pierce. FMPA received site certification in June 2006, and physical construction began on TCEC Unit 1 in August 2006. Construction is on schedule, and the scheduled in-service date for TCEC Unit 1 is May 2008.
- **Cane Island Combined Cycle:** FMPA is currently planning to construct a 296 MW combined cycle unit at the Cane Island Power Park site at KUA. The scheduled in-service date for Cane Island Unit 4 is summer 2011. FMPA plans to submit a "Need for Power" application (Need Determination) for Cane Island Unit 4 to the PSC in mid-2008.

- **2012 Peaking Unit:** FMPA is currently planning to construct 86 MW of combustion turbine (GT) peaking capacity with a planned in-service date of summer 2012. FMPA anticipates that this simple cycle GT unit could be installed at an ARP member owned generation site, most likely at the Tom G. Smith Power Plant site at Lake Worth, the Cane Island Power Park site at KUA, or at FMPA's TCEC site.
- **2013 Peaking Unit:** FMPA is currently planning to construct 149 MW of GT peaking capacity with a planned in-service date of summer 2013. FMPA anticipates that this simple cycle GT unit could be installed at an ARP member owned generation site, most likely at the Tom G. Smith Power Plant site at Lake Worth, the Cane Island Power Park site at KUA, or at FMPA's TCEC site.
- **2015 Peaking Unit:** FMPA is currently planning to construct an additional 86 MW of GT peaking capacity with a planned in-service date of summer 2015. This unit is similar to the 2012 Peaking Unit described above.

FMPA issued a Request for Power Supply Proposals (Power Supply RFP) in June 2007. The purpose of the Power Supply RFP was to determine whether a sufficient and cost-effective source of capacity and energy could be obtained as a replacement for Cane Island Unit 4, planned for commercial operation in 2011. No bids were received in response to this RFP. FMPA will continue to pursue sufficient and cost-effective alternatives to the peaking units that are planned for commercial operation in 2012, 2013, and 2015. Based on the outcome of these investigations, FMPA will determine whether to delay the in-service dates for these units.

Schedule 8 at the end of this section shows the planned and prospective ARP generating resources additions and changes.

5.3 Capacity and Purchase Power Requirements

The current system firm power supply purchase resources of ARP include purchases from PEF, FPL, Calpine, and Southern Company. The existing and future power purchase contracts are briefly summarized below:

- **PEF:** FMPA has a power contract with PEF for Partial Requirements (PR) Services. FMPA expects to take 30 MW in 2008, 75 MW in 2009, and 120 MW in 2010. The PR capacity also includes reserves. Additionally, FMPA has had discussions with PEF about participation in their Levy County nuclear project.
- **FPL:** FMPA has a long-term purchase contract with FPL for 45 MW until June 2013. The FPL long-term purchase includes reserves.

- **Calpine:** FMPA has a contract with Calpine that provides 100 MW until the contract expires in 2009.
- **Southern Company:** FMPA has a contract for 80 MW of purchase power, including KUA's share, from Southern Power's Stanton A that extends to 2013 for the initial term and has various extension options. FMPA is currently planning to exercise options to extend this contract at least through 2018. FMPA also has a contract for 156 MW of new peaking power from Southern Power's Oleander plant which began in December 2007. The purchase has a term of 20 years.

5.4 Summary of Current and Future ARP Resource Capacity

Tables 5-1 and 5-2 provide a summary, ten-year projection of the ARP resource capacity for the summer and winter seasons, respectively. A projection of the ARP fuel requirements by fuel type is shown in Schedule 5. Schedules 6.1 (quantity) and 6.2 (percent of total) present the forecast of ARP energy sources by resource type. Schedules 7.1 and 7.2 summarize the capacity, demand, and resulting reserve margin forecasts for the summer and winter seasons, respectively. Information on planned and prospective ARP generating facility additions and changes is located in Schedule 8.

Table 5-1
Summary of All-Requirements Project Resource Summer Capacity

Line No.	Resource Description	Summer Rating (MW) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	84	84	74	74	84	84	84	84	84	84
2	Stanton Coal Plant	224	224	186	186	186	186	186	186	186	186
3	Stanton CC Unit A	43	43	43	43	43	43	43	43	43	43
4	Cane Island 1-3	392	392	392	392	392	392	392	392	392	392
5	Indian River CTs	81	81	81	81	81	81	81	81	81	81
6	Key West Units 2&3	31	31	31	31	31	31	31	31	31	31
7	Key West Unit 4	45	45	45	45	45	45	45	45	45	45
8	Ft. Pierce Native Generation	-	-	-	-	-	-	-	-	-	-
9	Key West Native Generation	38	38	38	38	38	38	38	38	38	38
10	Kissimmee Native Generation	44	44	44	44	-	-	-	-	-	-
11	Lake Worth Native Generation	90	90	90	-	-	-	-	-	-	-
12	Vero Beach Native Generation	138	138	-	-	-	-	-	-	-	-
13	Sub Total Existing Resources	1,210	1,210	1,024	934	900	900	900	900	900	900
	Planned Additions										
14	Treasure Coast Energy Center	296	296	296	296	296	296	296	296	296	296
15	Cane Island 4	-	-	-	296	296	296	296	296	296	296
16	New Peaking Capacity	-	-	-	-	86	235	235	321	321	321
17	New Base/Intermediate Capacity	-	-	-	-	-	-	-	-	28	56
18	Sub Total Planned Additions	296	296	296	592	678	827	827	913	941	969
19	**Total Installed Capacity**	**1,506**	**1,506**	**1,320**	**1,526**	**1,578**	**1,727**	**1,727**	**1,813**	**1,841**	**1,869**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
20	Calpine Purchase	100	100	-	-	-	-	-	-	-	-
21	Stanton A Purchase	79	79	79	79	79	79	79	79	79	79
22	Oleander Purchase	156	156	156	156	156	156	156	156	156	156
23	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
24	Sub Total Without Reserves	335	335	235	235	235	235	235	235	235	235
	Firm Capacity Import With Reserves										
25	PEF Partial Requirements	30	75	120	-	-	-	-	-	-	-
26	FPL Long-Term Partial Requirements	45	45	45	45	45	-	-	-	-	-
27	Sub Total With Reserves	75	120	165	45	45	-	-	-	-	-
28	**Total Firm Capacity Import**	**410**	**455**	**400**	**280**	**280**	**235**	**235**	**235**	**235**	**235**
	Firm Capacity Export										
29	Vero Beach CROD Sale	-	-	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
30	**Total Firm Capacity Export**	**-**	**-**	**(21)**	**(21)**	**(21)**	**(21)**	**(21)**	**(21)**	**(21)**	**(21)**
31	**Total Available Capacity**	**1,916**	**1,961**	**1,699**	**1,785**	**1,837**	**1,941**	**1,941**	**2,027**	**2,055**	**2,083**

Table 5-2
Summary of All-Requirements Project Resource Winter Capacity

Line No.	Resource Description	Winter Rating (MW) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	86	86	75	75	85	85	85	85	85	85
2	Stanton Coal Plant	224	224	187	187	187	187	187	187	187	187
3	Stanton CC Unit A	45	45	45	45	45	45	45	45	45	45
4	Cane Island 1-3	408	408	408	408	408	408	408	408	408	408
5	Indian River CTs	100	100	100	100	100	100	100	100	100	100
6	Key West Units 2&3	31	31	31	31	31	31	31	31	31	31
7	Key West Unit 4	45	45	45	45	45	45	45	45	45	45
8	Ft. Pierce Native Generation	66	-	-	-	-	-	-	-	-	-
9	Key West Native Generation	38	38	38	38	38	38	38	38	38	38
10	Kissimmee Native Generation	46	46	46	46	-	-	-	-	-	-
11	Lake Worth Native Generation	94	94	94	94	-	-	-	-	-	-
12	Vero Beach Native Generation	144	144	-	-	-	-	-	-	-	-
13	Sub Total Existing Resources	1,327	1,261	1,069	1,069	939	939	939	939	939	939
	Planned Additions										
14	Treasure Coast Energy Center	-	318	318	318	318	318	318	318	318	318
15	Cane Island 4	-	-	-	-	318	318	318	318	318	318
16	New Peaking Capacity	-	-	-	-	-	96	273	273	368	368
17	New Base/Intermediate Capacity	-	-	-	-	-	-	-	-	-	28
18	Sub Total Planned Additions	-	318	318	318	636	732	909	909	1,004	1,032
19	**Total Installed Capacity**	**1,327**	**1,579**	**1,387**	**1,387**	**1,575**	**1,671**	**1,848**	**1,848**	**1,943**	**1,971**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
20	Calpine Purchase	100	100	-	-	-	-	-	-	-	-
21	Stanton A Purchase	84	84	84	84	84	84	84	84	84	84
22	Oleander Purchase	180	180	180	180	180	180	180	180	180	180
23	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
24	Sub Total Without Reserves	364	364	264	264	264	264	264	264	264	264
	Firm Capacity Import With Reserves										
25	PEF Partial Requirements	30	75	120	-	-	-	-	-	-	-
26	FPL Long-Term Partial Requirements	45	45	45	45	45	45	-	-	-	-
27	Sub Total With Reserves	75	120	165	45	45	45	-	-	-	-
28	**Total Firm Capacity Import**	**439**	**484**	**429**	**309**	**309**	**309**	**264**	**264**	**264**	**264**
	Firm Capacity Export										
29	Vero Beach CROD Sale	-	-	(23)	(23)	(23)	(23)	(23)	(23)	(23)	(23)
30	**Total Firm Capacity Export**	**-**	**-**	**(23)**	**(23)**	**(23)**	**(23)**	**(23)**	**(23)**	**(23)**	**(23)**
31	**Total Available Capacity**	**1,766**	**2,063**	**1,793**	**1,673**	**1,861**	**1,957**	**2,089**	**2,089**	**2,184**	**2,212**

Schedule 5
Fuel Requirements – All-Requirements Project

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Unit	Fuel	Actual	Forecasted									
No.	Fuel Type	Type	Units	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	Nuclear [1]		Trillion BTU	7	7	7	6	6	7	7	7	7	9	11
2	Coal		000 Ton	606	614	614	528	505	495	491	498	499	510	508
	Residual													
3		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	38	59	75	86	90	96	103	112	120	129	136
10		Total	000 BBL	38	59	75	86	90	96	103	112	120	129	136
	Natural Gas													
11		Steam	000 MCF	638	64	10	2	-	-	-	-	-	-	-
12		CC	000 MCF	14,396	24,967	27,588	26,505	33,224	37,094	38,772	39,676	40,531	40,962	40,863
13		CT	000 MCF	123	456	272	129	61	181	353	626	1,041	875	1,536
14		Total	000 MCF	15,157	25,487	27,869	26,636	33,285	37,275	39,126	40,302	41,572	41,836	42,398
15	Renewables [2]		Billion BTU	249	294	319	296	275	259	244	233	223	212	202
16	Other		Trillion BTU	-	0	0	0	0	0	0	0	0	0	0

[1] Nuclear generation is not part of the All-Requirements Project power supply. It is owned directly by some Project participants.
[2] Includes landfill gas consumed by FMPA's ownership share of the Stanton Energy Center as a supplemental fuel source, as well as bagasse consumed by U.S. Sugar cogeneration facility in the production of power purchased by FMPA.

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Annual Firm Inter-													
1	Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	601	686	641	584	580	682	629	681	656	795	1,011
3	Coal		GWh	1,558	1,562	1,559	1,345	1,298	1,270	1,261	1,280	1,286	1,324	1,328
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	19	26	35	41	44	47	53	58	63	67	72
11		Total	GWh	19	26	35	41	44	47	53	58	63	67	72
	Natural Gas													
12		Steam	GWh	38	4	1	0	-	-	-	-	-	-	-
13		CC	GWh	2,018	3,414	3,801	3,681	4,664	5,211	5,478	5,623	5,744	5,812	5,757
14		CT	GWh	12	42	25	12	6	18	36	62	107	90	158
15		Total	GWh	2,068	3,460	3,827	3,693	4,669	5,229	5,514	5,685	5,851	5,902	5,914
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		GWh	-	-	-	-	-	-	-	-	-	-	-
18	Renewables [2]		GWh	26	30	33	30	28	26	25	24	23	22	21
19	Interchange		GWh	2,976	1,883	1,793	1,636	935	461	403	336	366	317	265
20	Net Energy for Load [3]		GWh	7,248	7,648	7,888	7,329	7,553	7,715	7,884	8,062	8,245	8,427	8,611

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

[2] Includes power purchased from U.S. Sugar cogeneration facility and power generated from FMPA's ownership share of the Stanton Energy Center using landfill gas.

[3] Includes transmission losses.

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	8.3	9.0	8.1	8.0	7.7	8.8	8.0	8.4	8.0	9.4	11.7
3	Coal		%	21.5	20.4	19.8	18.3	17.2	16.5	16.0	15.9	15.6	15.7	15.4
	Residual													
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.3	0.3	0.4	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8
11		Total	%	0.3	0.3	0.4	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8
	Natural Gas													
12		Steam	%	0.5	0.1	0.0	0.0	-	-	-	-	-	-	-
13		CC	%	27.8	44.6	48.2	50.2	61.7	67.5	69.5	69.7	69.7	69.0	66.8
14		CT	%	0.2	0.6	0.3	0.2	0.1	0.2	0.5	0.8	1.3	1.1	1.8
15		Total	%	28.5	45.2	48.5	50.4	61.8	67.8	69.9	70.5	71.0	70.0	68.7
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		%	-	-	-	-	-	-	-	-	-	-	-
18	Renewables [2]		%	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2
19	Interchange		%	41.1	24.6	22.7	22.3	12.4	6.0	5.1	4.2	4.4	3.8	3.1
20	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.

[2] Includes power purchased from U.S. Sugar cogeneration facility and power generated from FMPA's ownership share of the Stanton Energy Center using landfill gas.

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	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	System Firm Summer Peak Demand	Reserve Margin before Maintenance [3]		Scheduled Maintenance	Reserve Margin after Maintenance [3]	
Year	(MW) [1]	(MW)	(MW)	QF (MW)	(MW)	(MW) [2]	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2008	1,506	410	0	0	1,916	1,545	371	25%	0	371	25%
2009	1,506	455	0	0	1,961	1,594	367	25%	0	367	25%
2010	1,320	400	(21)	0	1,699	1,463	237	18%	0	237	18%
2011	1,526	280	(21)	0	1,785	1,507	278	19%	0	278	19%
2012	1,578	280	(21)	0	1,837	1,540	297	20%	0	297	20%
2013	1,727	235	(21)	0	1,941	1,574	366	23%	0	366	23%
2014	1,727	235	(21)	0	1,941	1,610	330	21%	0	330	21%
2015	1,813	235	(21)	0	2,027	1,648	380	23%	0	380	23%
2016	1,841	235	(21)	0	2,055	1,685	370	22%	0	370	22%
2017	1,869	235	(21)	0	2,083	1,724	360	21%	0	360	21%

[1] See Table 5-1 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Summer Peak Demand includes transmission losses for the members served through FPL, PEF (beginning in 2011), and KUA.

[3] Reserve Margin calcuated as [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases). See Appendix III to this Ten-Year Site Plan for the calculation of reserve margins.

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 (MW) [1]	Firm Capacity Import (MW) [1]	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Winter Peak Demand (MW) [2]	Reserve Margin before Maintenance [3] (MW)	Reserve Margin before Maintenance [3] (% of Peak)	Scheduled Maintenance (MW)	Reserve Margin after Maintenance [3] (MW)	Reserve Margin after Maintenance [3] (% of Peak)
2007/08	1,327	439	0	0	1,766	1,428	338	25%	0	338	25%
2008/09	1,579	484	0	0	2,063	1,474	590	44%	0	590	44%
2009/10	1,387	429	(23)	0	1,793	1,321	473	41%	0	473	41%
2010/11	1,387	309	(23)	0	1,673	1,360	313	24%	0	313	24%
2011/12	1,575	309	(23)	0	1,861	1,390	471	35%	0	471	35%
2012/13	1,671	309	(23)	0	1,957	1,422	535	39%	0	535	39%
2013/14	1,848	264	(23)	0	2,089	1,454	635	44%	0	635	44%
2014/15	1,848	264	(23)	0	2,089	1,488	601	40%	0	601	40%
2015/16	1,943	264	(23)	0	2,184	1,523	662	43%	0	662	43%
2016/17	1,971	264	(23)	0	2,212	1,557	655	42%	0	655	42%

[1] See Table 5-2 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Winter Peak Demand includes transmission losses for the members served through FPL, PEF (beginning in 2011), and KUA.

[3] Reserve Margin calcuated as [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases). See Appendix III to this Ten-Year Site Plan for the calculation of reserve margins.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Primary	Fuel Alt.	Fuel Transport Primary	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Resource Additions														
Treasure Coast Energy Center	Unit 1	St. Lucie	CC	NG	DFO	PL	TK	NA	05/08	NA	NA	296	318	V
Cane Island	CC4	Osceola	CC	NG	-	PL	-	NA	05/11	NA	NA	296	318	P
Unsited Combustion Turbine	CT1	Unknown	GT	NG	DFO	PL	TK	NA	06/12	NA	NA	86	96	P
Unsited Combustion Turbine	CT2	Unknown	GT	NG	DFO	PL	TK	NA	06/13	NA	NA	149	177	P
Unsited Combustion Turbine	CT3	Unknown	GT	NG	DFO	PL	TK	NA	06/15	NA	NA	86	86	P
Changes to Existing Resources														
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	NA	05/76	01/08	50	(42)	(45)	RT
H.D. King	5	St. Lucie	CA	WH	-	-	-	NA	01/53	04/08	8	(7)	(8)	RT
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	NA	01/64	04/08	32	(28)	(30)	RT
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	NA	05/90	04/08	23	(21)	(23)	RT
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	NA	04/70	04/08	3	(3)	(3)	RT
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	NA	04/70	04/08	3	(3)	(3)	RT
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	NA	12/76	05/11	31	(26)	(27)	RT
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	NA	03/78	05/11	20	(21)	(21)	RT
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	NA	12/65	05/11	2	(2)	(2)	RT
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	NA	12/65	05/11	2	(2)	(2)	RT
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	NA	12/65	05/11	2	(2)	(2)	RT
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	NA	12/65	05/11	2	(2)	(2)	RT
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	NA	12/65	05/11	2	(2)	(2)	RT
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	NA	11/67	05/11	27	(26)	(27)	RT
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	NA	03/78	05/11	10	(8)	(9)	RT
Hansel Plant	21	Osceola	CT	NG	-	PL	-	NA	02/83	12/11	38	(29)	(35)	RT
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(5)	RT
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(5)	RT

Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

Community Power + Statewide Strength

Section 6 Site and Facility Descriptions

Florida Public Service Commission Rule 25-22.072 F.A.C. requires that the State of Florida Public Service Commission Electric Utility Ten-Year Site Plan Information and Data Requirements Form PSC/EAG 43 dated 11/97 govern the submittal of information regarding Potential and Identified Preferred sites. Ownership or control is required for sites to be Potential or Identified Preferred. The following are Potential and Identified Preferred sites for FMPA as specified by PSC/EAG 43.

- Treasure Coast Energy Center – Identified Preferred Site for Treasure Coast Energy Center Unit 1 and Potential Site for additional future generation.
- Cane Island Power Park – Identified Preferred Site for Cane Island Unit 4 and Potential Site for additional future generation.
- Tom G. Smith – Potential Site.
- Stock Island – Potential Site.

FMPA anticipates that simple cycle combustion turbines could be installed at an ARP member owned generation site, such as the Tom G. Smith Power Plant site at Lake Worth, the Cane Island Power Park site at KUA, or FMPA's Treasure Coast Energy Center site. FMPA anticipates that combined cycle generation could be installed at an existing ARP site, either at Cane Island Power Park or at Treasure Coast Energy Center. FMPA continuously explores the feasibility of other sites located within Florida with the expectation that member cities would provide the best option for future development.

Treasure Coast Energy Center

FMPA is currently constructing a new 296 MW, 1x1 7FA combined cycle facility at the Treasure Coast Energy Center site. The Treasure Coast Energy Center is located in St. Lucie County in the City of Fort Pierce. The site was certified in June 2006 and can accommodate construction of future units beyond TCEC Unit 1, up to a total of 1,200 MW. Physical construction of TCEC Unit 1 commenced in August 2006, and commercial operation is scheduled for May 2008.

Cane Island Power Park

FMPA is currently planning to construct a new 296 MW, 1x1 7FA combined cycle facility at the Cane Island Power Park. FMPA plans to submit an application for Need Determination for Cane Island Unit 4 to the PSC in mid-2008.

Cane Island Power Park is located south and west of KUA's service area and contains 392 MW (summer) of gas turbine and combined cycle capacity. The Cane Island Power Park currently 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.

Tom G. Smith Power Plant

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 90 MW (summer) 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.

Stock Island

The Stock Island site currently consists of five diesel generating units, as well as four combustion turbines. The site receives water from the Florida Keys Aqueduct Authority via a pipeline from the mainland, and also uses on-site groundwater. The site receives delivery of fuel oil to its unloading system through waterborne delivery, and also has the capability of receiving fuel oil deliveries via truck.

Schedules 9.1 through 9.5 present the status report and specifications for each of the proposed ARP generating facilities. Schedule 10 contains the status report and specifications for proposed ARP transmission line projects.

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

(1)	Plant Name and Unit Number	Treasure Coast Energy Center Unit 1
(2)	Capacity	
	a. Summer	296
	b. Winter	318
(3)	Technology Type	CC (1x1 GE 7FA)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	Aug-06
	b. Commercial In-Service Date	May-08
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	69 Acres
(9)	Construction Status	Under construction, more than 50% complete
(10)	Certification Status	Approved
(11)	Status with Federal Agencies	Approved
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	3.8%
	Forced Outage Factor (FOF)	2.0%
	Equivalent Availability Factor	94.3%
	Resulting Capacity Factor	67.6%
	Average Net Operating Heat Rate (ANOHR)	6,969 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,022
	Direct Construction Cost (2008 $/kW)	$944
	AFUDC Amount ($/kW) [1]	$77
	Escalation ($/kW)	$0
	Fixed O&M ($/kW)	9.06 $/kW-yr
	Variable O&M ($/MWh)	$3.30

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Cane Island Unit 4
(2)	Capacity	
	a. Summer	296
	b. Winter	318
(3)	Technology Type	CC (1x1 GE 7FA)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2009
	b. Commercial In-Service Date	May-11
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	n/a
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	167 Acres
(9)	Construction Status	Planned
(10)	Certification Status	Planned
(11)	Status with Federal Agencies	Planned
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	3.8%
	Forced Outage Factor (FOF)	2.0%
	Equivalent Availability Factor	94.3%
	Resulting Capacity Factor	68.4%
	Average Net Operating Heat Rate (ANOHR)	6,969 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,372
	Direct Construction Cost (2008 $/kW)	$1,204
	AFUDC Amount ($/kW)	$104
	Escalation ($/kW)	$64
	Fixed O&M ($/kW)	4.56 $/kW-yr
	Variable O&M ($/MWh)	$3.30

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

(1)	Plant Name and Unit Number	Unsited Combustion Turbine Unit 1
(2)	Capacity	
	a. Summer	86
	b. Winter	96
(3)	Technology Type	GT
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2010
	b. Commercial In-Service Date	Jun-12
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Planned
(11)	Status with Federal Agencies	Planned
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	2.0%
	Equivalent Availability Factor	96.1%
	Resulting Capacity Factor	7.9%
	Average Net Operating Heat Rate (ANOHR)	9,451 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,030
	Direct Construction Cost (2008 $/kW)	$898
	AFUDC Amount ($/kW) [1]	$42
	Escalation ($/kW)	$90
	Fixed O&M ($/kW)	13.45 $/kW-yr
	Variable O&M ($/MWh)	$3.29

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Unsited Combustion Turbine Unit 2
(2)	Capacity	
	a. Summer	149
	b. Winter	177
(3)	Technology Type	GT
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2011
	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	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Planned
(11)	Status with Federal Agencies	Planned
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	2.0%
	Equivalent Availability Factor	96.1%
	Resulting Capacity Factor	0.7%
	Average Net Operating Heat Rate (ANOHR)	11,871 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$761
	Direct Construction Cost (2008 $/kW)	$649
	AFUDC Amount ($/kW) [1]	$30
	Escalation ($/kW)	$82
	Fixed O&M ($/kW)	8.41 $/kW-yr
	Variable O&M ($/MWh)	$15.57

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Unsited Combustion Turbine Unit 3
(2)	Capacity	
	a. Summer	86
	b. Winter	96
(3)	Technology Type	GT
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2013
	b. Commercial In-Service Date	Jun-15
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Planned
(11)	Status with Federal Agencies	Planned
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	2.0%
	Equivalent Availability Factor	96.1%
	Resulting Capacity Factor	8.4%
	Average Net Operating Heat Rate (ANOHR)	9,449 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,102
	Direct Construction Cost (2008 $/kW)	$898
	AFUDC Amount ($/kW) [1]	$42
	Escalation ($/kW)	$162
	Fixed O&M ($/kW)	13.45 $/kW-yr
	Variable O&M ($/MWh)	$3.29

[1] Includes AFUDC and bond issuance expenses

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

(1)	Point of Origin and Termination	
(2)	Number of Lines	
(3)	Right-of-Way	
(4)	Line Length	
(5)	Voltage	(See note below)
(6)	Anticipated Construction Timing	
(7)	Anticipated Capital Investment	
(8)	Substations	
(9)	Participation with Other Utilities	

Note: FMPA currently has no new proposed transmission lines.

Florida Municipal Power Agency

Appendix I

List of Abbreviations

Community Power + Statewide Strength

Appendix I
List of Abbreviations

Generator Type

CA	Steam Portion of Combined Cycle
CC	Combined Cycle (Total Unit)
CT	Combustion Turbine Portion of Combined Cycle
GT	Combustion Turbine
IC	Internal Combustion Engine
NP	Nuclear Power
ST	Steam Turbine

Fuel Type

BIT	Bituminous Coal
DFO	Distillate Fuel Oil
NG	Natural Gas
RFO	Residual Fuel Oil
UR	Uranium
WH	Waste Heat

Fuel Transportation Method

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water Transportation

Status of Generating Facilities

P	Planned Unit (Not Under Construction)
L	Regulatory Approval Pending. Not Under Construction
RT	Existing Generator Scheduled for Retirement
U	Under Construction, Less Than or Equal to 50% Complete.
V	Under Construction, More Than 50% Complete.

Other

NA	Not Available or Not Applicable

Florida Municipal Power Agency

Appendix II

Other Member Transmission Information

Community Power + Statewide Strength

Appendix II
Member Transmission Information

Table II-1 presented on the following pages 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.

Table II-1
Planned and Proposed Transmission Additions for ARP Members
2008 through 2017 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Ft. Pierce	Hartman Auto-Xfmr1Upgrade		100	138/69 kV	1	5/2008
	Hartman Auto-Xfmr2 Upgrade		100	138/69 kV	2	5/2008
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	1	9/2010
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	2	9/2010
	Southwest Substation			138/13.2 kV		9/2010
Jacksonville Beach	Jacksonville Beach Substation (Reconductor)	JEA Neptune Substation		138 kV	1	6/2011
Key West	SIS 3rd Ave Transformer			69/13.8kV		3/2009
Kissimmee	Hansel (Reconductor)	C.A.Wall		69 kV	1	6/2008
	Pleasant Hill Substation	Hansel		69 kV	1	6/2008
	Pleasant Hill Substation	Clay Street		69 kV	1	6/2008
	Pleasant Hill Substation			69 kV		6/2008
	Cane Island (Reconductor)	Tie Point (Taft)		230 kV	1	4/2010
	Cane Island (Reconductor)	Tie Point (Osceola)		230 kV	1	4/2010
	C.A.Wall	Turnpike		69 kV	1	6/2010
	Domingo Toro Substation			69 kV	1	6/2011
	Domingo Toro Substation	Tie Point with St.Cloud		69 kV	1	6/2011
	Clay Street (Reconductor)	Airport		69 kV	1	6/2011
	Clay Auto-Txfmr		200	230/69 kV	2	6/2011
	Upgrade 230kV Breakers at Cane Island Substation			230 kV		6/2011
	Osceola Parkway Substation					6/2012
	Lake Bryan	Osceola Parkway		69 kV	1	6/2012
	Lake Cecile	Osceola Parkway		69 kV	1	6/2012
	Marydia Auto-Txfmr (Upgrade)		200	230/69 kV	1	6/2016

Table II-1 (Continued)
Planned and Proposed Transmission Additions for ARP Members
2008 through 2017 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Ocala	Nuby's Corner Substation		25	69 kV		6/2008
	Nuby's Corner	Silver Springs		69 kV	1	6/2008
	Nuby's Corner	Baseline Rd		69 kV	1	6/2008
	Ergle Substation Third Breaker			69 kV		6/2009
	Ergle	Silver Springs		69 kV	1	6/2009
	Dearmin	Baseline Rd		69 kV	1	6/2009
	Dearmin / Baseline Substation (Improvements)			69 kV		6/2009
	Fore Corners Substation		30	69 kV		6/2010
	Fore Corners	Ergle		69 kV	1	6/2010
	Fore Corners	Ocala North		69 kV	1	6/2010
	Shaw Second 30 MVA Transformer		30	69 kV		6/2010
	Shaw	Silver Springs		230 kV	1	6/2012
Vero Beach	Sub #8 Upgrade		25/33	69/13.2kV		12/2009

Florida Municipal Power Agency

Appendix III

Additional Reserve Margin Information

Community Power + Statewide Strength

Appendix III
Additional Reserve Margin Information

FMPA excludes Partial Requirements (PR) purchases that are being supplied by the PR utility in the calculation of reserves being supplied in Schedules 7.1 and 7.2. The PR utility is required to serve the ARP load equivalent to that of the PR utility's own native load. Thus, the PR purchase by FMPA is equal to the purchase capacity plus equivalent reserves of the selling utility and therefore does not require additional reserves to be carried by FMPA. Tables III-1 and III-2 below are provided as supplements to Ten-Year Site Plan Schedules 7.1 and 7.2 to demonstrate how the reserve margin percentages were calculated for the summer and winter peaks, respectively.

Table III-1
Calculation of Reserve Margin at Time of Summer Peak
All-Requirements Project

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2008	1,916	1,545	75	371	25%
2009	1,961	1,594	120	367	25%
2010	1,699	1,463	165	237	18%
2011	1,785	1,507	45	278	19%
2012	1,837	1,540	45	297	20%
2013	1,941	1,574	0	366	23%
2014	1,941	1,610	0	330	21%
2015	2,027	1,648	0	380	23%
2016	2,055	1,685	0	370	22%
2017	2,083	1,724	0	360	21%

[1] Reserve Margin MW calculated as follows: (Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)

[2] Reserve Margin % calculated as follows: [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases)

Table III-2
Calculation of Reserve Margin at Time of Winter Peak
All-Requirements Project

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2007/08	1,766	1,428	75	338	25%
2008/09	2,063	1,474	120	590	44%
2009/10	1,793	1,321	165	473	41%
2010/11	1,673	1,360	45	313	24%
2011/12	1,861	1,390	45	471	35%
2012/13	1,957	1,422	45	535	39%
2013/14	2,089	1,454	0	635	44%
2014/15	2,089	1,488	0	601	40%
2015/16	2,184	1,523	0	662	43%
2016/17	2,212	1,557	0	655	42%

[1] Reserve Margin MW calculated as follows: (Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)

[2] Reserve Margin % calculated as follows: [(Total Available Capacity - Partial Requirements Purchases) - (System Firm Peak Demand - Partial Requirements Purchases)] / (System Firm Peak Demand - Partial Requirements Purchases)