FMPA

Florida Municipal Power Agency

Michele A. Jackson, P.E.
System Planning Manager

March 30, 2009

Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

100000-OT

Re: FMPA's 2010 Ten Year Site Plan

Dear Sir/Madam:

Pursuant to Rule 25-22.071(1) Florida Administrative Code, FMPA is hereby submitting 25 copies of its 2010 Ten Year Site Plan. If you have any questions, please do not hesitate to contact me at (321) 239-1013.

Sincerely,

Michele A. Jackson

Michele A. Jackson, P.E.
System Planning Manager

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Florida Municipal Power Agency

Ten-Year Site Plan

April 2010

Community Power + Statewide Strength®

Florida Municipal Power Agency

Ten-Year Site Plan 2010-2019

Submitted to

Florida Public Service Commission

April 1, 2010

Community Power + Statewide Strength ®

FLORIDA MUNICIPAL POWER AGENCY

2010 Ten-Year Site Plan

March 30, 2010

Florida Municipal Power Agency

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Executive Summary

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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 provides, among other things, a description of existing electric utility resources, a 10-year forecast of electric power generating needs and an identification of the general location and type of any proposed generation capacity and transmission additions for the next 10-year period.

The Florida Municipal Power Agency (FMPA or the Agency) is a project-oriented, joint-action agency. There are currently 30 Members of FMPA – each a municipal electric utility – located throughout the State of Florida. As a joint-action agency, FMPA facilitates opportunities for FMPA Members in participation in power supply projects developed by third-party Florida utilities and other power producers. For example, FMPA facilitated the participation of 15 FMPA Members in an 8.8 percent undivided ownership interest in the St. Lucie Nuclear Power Plant Unit No. 2 developed by Florida Power & Light Company (FPL). FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (the ARP), where the Agency has committed to planning for and supplying all of the power requirements of 14 FMPA Members (the ARP Participants). FMPA's TYSP is focused on the resources of, and planning for, the ARP.

The total summer capacity of ARP resources for the year 2010 is 1,692 MW. This capacity is comprised of ARP Participant entitlements and ownership shares in two nuclear power plants in the State of Florida, ARP owned resources, ARP Participant-owned resources, and power purchase agreements, and is summarized below in Table ES-1.

Table ES-1
FMPA ARP Summer 2010 Capacity Resources

Resource Category	Summer Capacity (MW)
Nuclear	74
ARP Ownership	818
ARP Participant Ownership	397
Power Purchases	404
Total 2010 ARP Resources	1,692

FMPA, as agent for the ARP, has one power plant currently under construction. Cane Island Unit 4 (CI4), a nominal 300 MW (summer rating) combined cycle unit to be constructed at the Cane Island Power Park in Osceola County, is expected to begin commercial operation in the spring of 2011. In August 2008, the Florida Public Service Commission granted FMPA's petition for determination of need for CI4. The Florida Department of Environmental Protection issued final approval under the Florida Power Plant Siting Act in December 2008. Construction of CI4 began in the spring of 2009.

Based on recent projections of ARP load, the addition of CI4 will allow the ARP to meet its generation capacity requirements until 2019. At this time, FMPA is planning to meet the ARP's need for additional generation capacity in 2019 through a power purchase from a supplier to be determined. FMPA will continue to evaluate and develop sufficient and cost-effective resource alternatives for the ARP through its integrated resource planning process.

FMPA is actively involved in planning and developing new renewable energy resources and demand side resource opportunities consistent with, and in consideration of the planning requirements of the State of Florida and the Public Utility Regulatory Policies Act (PURPA). Currently, FMPA purchases renewable energy from a cogeneration plant fueled by sugar bagasse, and utilizes landfill gas as a secondary fuel to supplement its coal fuel requirements. In December 2009, FMPA commissioned its first solar photovoltaic system, a jointly-owned 30 kW system located in Key West, FL. In addition, FMPA is piloting several Demand Side Management programs with ARP Participants aimed at energy efficiency, fuel switching, and load management.

A location map of the ARP Participants and FMPA's power resources as of January 1, 2010 is shown in Figure ES-1.

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

Florida Municipal Power Agency

Section 1.0

Description of FMPA

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Section 1 Description of FMPA

1.1 FMPA

Florida Municipal Power Agency (FMPA or the Agency) 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 specifies 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 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. 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.

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 14 members, representing the 15 participants in the All-Requirements Power Supply Project (ARP)[1]. 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 ARP to secure an adequate, economical, and reliable supply of electric capacity and energy as directed by FMPA Members. Currently, 15 FMPA Members (the ARP Participants) participate in the ARP. The geographical locations of the ARP Participants are shown in Figure 1-1.

Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP Participants. The ARP began delivering capacity and energy to these original five participants in 1986. The remaining 10 ARP Participants 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.

ARP Participants are required to purchase all of their capacity and energy requirements from the ARP pursuant to the All-Requirements Power Supply Project Contract at a rate that is established by the Executive Committee to recover all ARP costs. Those ARP Participants that own generating capacity sell the electric capacity and energy of their generating resources to the ARP pursuant to a Capacity & Energy Sales Agreement between FMPA and the ARP Participant, and receive capacity and energy (C&E) payments.

[1] As further discussed in this section, the City of Vero Beach has exercised the right to modify its ARP full requirements membership. While it remains a participant in the ARP, effective January 1, 2010, Vero Beach no longer is purchasing capacity and energy from the ARP and no longer has a representative on the Executive Committee.

Figure 1-1
ARP Participant Cities

On December 9, 2004, the City of Vero Beach provided notice to FMPA, pursuant to the All-Requirements Power Supply Project Contract, that it will exercise the right to modify its ARP full requirements membership beginning January 1, 2010. In addition, on December 17, 2008, the City of Lake Worth provided notice to FMPA that it will exercise the right to modify its ARP full requirements membership beginning January 1, 2014. The effect of these notices is that the ARP will no longer utilize the cities' generating resources, and the ARP will commence serving the cities' load on a partial requirements basis. The amount of the partial requirements for Vero Beach served by the ARP has been established as zero MW, and the amount of the partial requirements for Lake Worth served by the ARP will be established in 2013.

Following is a brief description of each of the ARP Participants.

City of 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.

City of 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.cityofclewiston.org.

City of 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. 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 Thiess 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.

City of 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.townofhavana.com.

City of Jacksonville Beach

The City of Jacksonville Beach is located in northeast Florida in Duval County. Jacksonville Beach's electric department, operating under the name Beaches Energy Services (Beaches), 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 Director of Electric Utilities. Beaches' service area is approximately 45 square miles. For more information about Beaches, please visit www.beachesenergy.com.

Keys Energy Services

The Utility Board of the City of Key West, Florida, doing business as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998. 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

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

City of Lake Worth

The City of Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002. Rebecca M. Mattey is the Utility Director. 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.

City of 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.

City of 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 Director. The City's service area is approximately 3 square miles. For more information about the City of Newberry, please visit www.ci.newberry.fl.us.

City of Ocala

The City of Ocala, doing business as Ocala Utility Services, is located in central Florida in Marion County. The City joined the ARP in May 1986. Ricky A. Horst is the City Manager, and Matthew J. Brower is the Assistant City Manager/Utility Services. The City's service area is approximately 161 square miles. For more information about Ocala Utility Services, please visit www.ocalaelectric.com.

City of Starke

The City of Starke is located in north Florida in Bradford County. The City joined the ARP in October 1997. Ricky Thompson is the 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.

City of 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. John Lee is Manager of Customer Service and Acting Utility Director. The City's service area is approximately 41 square miles. 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 facilitates the participation of FMPA Members in four, third-party power supply projects as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit. 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 FMPA Members are participants in the St. Lucie Project, with the following entitlements to FMPA's undivided ownership interest 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 FMPA Members are participants in the Stanton Project with entitlements to FMPA's undivided interest 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 FMPA 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 FMPA 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, 2010.

Table 1-5
Summary of FMPA Power Supply Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Power Supply 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	
Utility Board of the City of Key West			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 [1]	X

[1] Effective January 1, 2010, the City of Vero Beach has exercised the right to modify its ARP full requirements membership.

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 nuclear capacity entitlements or ownership shares, ARP-owned generation capacity, ARP member-owned generation capacity, and power purchase contracts. The supply side resources for the ARP for the 2010 summer season are shown by ownership capacity in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2010

Resource Category	Summer Capacity (MW)
1) Nuclear	74
2) ARP Ownership	
Existing	818
New	-
Sub Total ARP Ownership	818
3) Participant Ownership	
KEYS	31
KUA	278
Lake Worth	88
Sub Total Participant Ownership	397
4) Power Purchases	404
Total 2010 ARP Resources	1,692

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

1) **Nuclear Generation:** A number of the ARP Participants own small amounts of capacity in Progress Energy Florida's Crystal River Unit 3. Likewise, a number of ARP Participants also participate in FMPA's St. Lucie Project, which provides them entitlement to capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "Excluded Resources" in the All-Requirements Power Supply Project Contract between FMPA and the ARP Participants. As such, the ARP Participants pay their own costs associated with the nuclear units and individually receive

the benefits of the capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for these ARP Participants. As Excluded Resources, ARP Participants' ownership shares or entitlements in the nuclear units are considered in the capacity planning for the ARP.

2) **ARP Owned Generation:** This category includes generation that is owned by FMPA as agent for the ARP as well as generation assigned to the ARP by ARP Participants via their participation in other Agency projects. Such ARP ownership capacity includes portions of the Stanton Energy Center (including Stanton Unit No. 1, Stanton Unit No. 2, and the Stanton A combined cycle unit), Indian River, Cane Island, Treasure Coast, and Stock Island units.

3) **Participant Owned Generation:** Capacity included in this category is generation owned by the ARP Participants. The ARP purchases this capacity through Capacity and Energy Sales Agreements between FMPA and the ARP Participant, and then commits and dispatches the generation to meet the total requirements of the ARP.

4) **Power Purchases:** This category includes power purchases between FMPA, as agent for the ARP, and third-parties. Purchased power generation includes capacity and energy purchased from PEF, FPL, and Southern Company.

Information regarding existing ARP generation resources as of December 31, 2009, 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. FPL, 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, OUC, JEA, Seminole Electric Cooperative, Florida Keys Electric Cooperative Association (FKEC), and Tampa Electric Company (TECO).

The ARP transmits capacity and energy to the ARP Participants utilizing the transmission systems of FPL, PEF, and OUC. Capacity and energy for the Cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, Lake Worth, and Starke are transmitted across FPL's transmission system. Capacity and energy for the Cities of Ocala, Leesburg, Bushnell, Newberry, Havana, and Ft. Meade are transmitted across the PEF transmission system.

Capacity and energy for KUA is transmitted across the transmission systems of FPL, PEF and OUC.

2.2.1 ARP Participant Transmission Systems

FPUA

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. There are two interconnections with other utilities, both at 138 kV. The FPUA's Hartman Substation interconnects to FPL's Hartman-Midway #1, Hartman-Midway #2, and Emerson via Fort Pierce 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

KEYS owns and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy south of FKEC's 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 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 plant is rated at approximately 88 MW (summer rating). 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.

KUA

KUA serves a total area of approximately 85 square miles, and owns 24.6 circuit miles of 230 kV and 52.8 circuit miles of 69 kV transmission lines that deliver capacity and energy to 10 distribution substations. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. 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 East 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.

Ocala Utility Services

Ocala Utility Services (OUS) owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles of radial 230 kV transmission, 48 miles of a 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.

OUS's 230kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs North Switching Station. OUS's Dearmin Substation ties at PEF's Silver Springs Switching Station and OUS's Ergle Substation ties at SECI's Silver Springs North Switching Station. OUS also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OUS owns a 13 mile, radial 230 kV transmission line from Ergle Substation to Shaw Substation. OUS 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 owns a looped, 69 kV transmission system for system load and a 144 MW local power plant. Vero Beach has two 138 kV interconnections with FPL and one with FPUA. Vero Beach's interconnection with FPL is at Vero Beach's West Substation No. 7. Vero Beach 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. Vero Beach & 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.

Beaches

Beaches owns the 230 kV Sampson transmission switching station that interconnects to FPL at FPL's Orangedale Substation and JEA at JEA's Switzerland Substation. Beaches has a second interconnection that ties to JEA's Neptune Beach Substation from its Penman Substation at 138 kV.

Three auto-transformers at Sampson substation provide transformation from 230 kV to 138 kV. Beaches has five 138 kV substations and five distribution substations, which deliver energy at 12.47 kV and 26.4 kV to its distribution system. Beaches owns 47.9 miles of 138 kV transmission lines.

City of Clewiston

The City of Clewiston owns the 138 kV McCarthy transmission switching station that interconnects to FPL at FPL's Okeelanta and Clewiston substations. Clewiston owns two 3.5 mile 138 kV transmission lines from its McCarthy substation to the City of Clewiston substation. Two transformers at the City of Clewiston substation provide transformation from 138 kV to 12.47 kV to its distribution system.

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 ARP Participants. 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 ARP Participants as points of delivery. 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
Existing Generating Facilities as of December 31, 2009

(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	25	25
St Lucie	2	St Lucie	NP	UR	-	TK	-	08/83	NA	891	60 [1]	61 [1]
Total Nuclear Capacity											85	86
ARP Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	102 [1]	103 [1]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	101 [1]	101 [1]
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	16	17
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	52	54
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	116	120
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
Treasure Coast	1	St Lucie	CC	NG	DFO	PL	TK	05/08	NA	315	300	310
Total ARP Owned Generation											856	892
Participant Owned Generation												
Vero Beach												
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	NA	13	11 [1]	12 [1]
Municipal Plant	2	Indian River	CA	WH	-	-	-	08/64	NA	13	12 [1]	11 [1]
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	09/71	NA	33	32 [1]	33 [1]
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	08/76	NA	56	51 [1]	53 [1]
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	NA	40	32 [1]	35 [1]
Sub Total Vero Beach											138	144

[1] Capabilities shown are as of December 31, 2009. The City of Vero Beach has exercised the right to modify its ARP full requirements membership. Effective January 1, 2010, the ARP will no longer Utilize Vero Beach's generating resources, including its entitlement shares in the Stanton, Stanton II, and St Lucie Projects. See Schedule 8 for information on the change in net capabilities for the ARP for these resources effective January 1, 2010.

Schedule 1 (Continued)
Existing Generating Facilities as of December 31, 2009

(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	-	02/83	12/12	38	28	34
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	12/12	8	8	5
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	12/12	8	8	5
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	16	17
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	52	54
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	116	120
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											278	291
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	12/76	NA	31	26	27
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	03/78	NA	20	20	21
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	12/65	NA	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	12/65	NA	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	12/65	NA	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	12/65	NA	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	12/65	NA	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	NA	27	24	25
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	03/78	NA	10	8	9
Sub Total Lake Worth											88	92
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	12/09	2	0	0
Stock Island HSD	IC2	Monroe	IC	DFO	-	WA	-	01/65	12/09	2	0	0
Stock Island HSD	IC3	Monroe	IC	DFO	-	WA	-	01/65	12/09	2	0	0
Stock Island MSD	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	6	6
Stock Island MSD	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	7	7
Sub Total Keys											31	31
Total Participant Owned Generation											535	559
Total Generation Resources											1,476	1,537

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

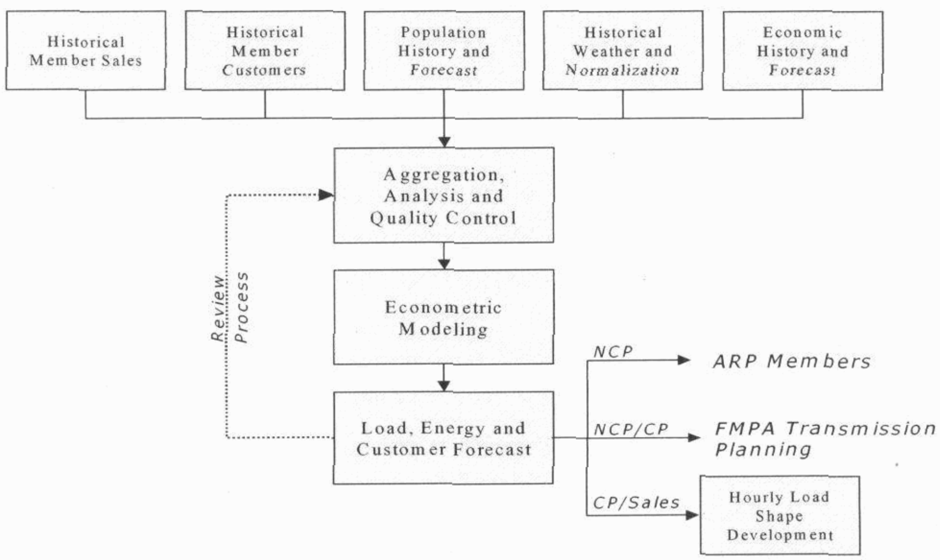
3.1 Introduction

To secure sufficient capacity and energy, FMPA forecasts each ARP Participant's electrical power demand and energy requirements on an individual basis and aggregates 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 Participants. Forecasts are prepared on an individual Participants 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 Participants. 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 2010 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2010 through 2029. The Forecast was prepared on a monthly basis using municipal utility data provided to FMPA by the ARP Participants and load data maintained by FMPA. Historical and projected economic and demographic data were provided by Moody's Economy.com and Woods & Poole Economics, nationally recognized providers of such data. The Forecast also relied on information regarding local economic and demographic issues specific to each ARP member. Weather data was provided by the National Oceanic and Atmospheric Administration (NOAA) for a variety of weather stations in close proximity to the ARP Participants.

The Forecast reflects the City of Vero Beach Notice of Establishment of Contract Rate of Delivery and the City of Lake Worth Notice of Establishment of Contract Rate of Delivery (CROD). The Forecast assumed that Vero Beach's CROD becomes effective on January 1, 2010. Also, the Forecast assumed that Lake Worth's CROD becomes effective on January 1, 2014; 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. 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 Participant'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 Participants. 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 Participants. 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 Participants and the number of households in each ARP Participant'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 ARP Participant'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 Participant. 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 ARP Participant system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1998-2009.

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 Participant groups, and the transmission providers were derived from monthly coincidence factors averaged generally over a 5-year period (2005-2009). 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 Participant group peaks was determined from an appropriate summation of the hourly load data.

3.5 Data Sources

3.5.1 Historical ARP Participant Retail Sales Data

Data was generally available and analyzed over January 1992 through September 2009 (Study Period). Data included historical customer counts, sales, and revenues by rate classification for each of the ARP Participants. However, for a small, early 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 Participants. In most cases, the closest "first-order" weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data. In two cases (Beaches and FPUA), 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 Participants' 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.

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 NOAA.

3.5.3 Economic Data

Moody's Economy.com and Woods & Poole Economics, both nationally recognized providers of economic data, provided both historical and projected economic and demographic data for each of the 15 counties in which the ARP Participants' service territories reside (the service territory of Beaches 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 Participants' 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 2.0% from 2010-2019, and at 1.4% from 2020-2029. The Base Case 2010 ARP forecast summer peak demand is 1,264 MW and forecast annual NEL is 6,095 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 ARP Participant 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 1971-2005. 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 Power Supply 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
2000	NA	NA	2,063	154,855	13,321	1,723	28,401	60,655
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	3,178	227,990	13,941	2,603	42,120	61,800
2004	NA	NA	3,172	234,589	13,523	2,630	42,916	61,274
2005	NA	NA	3,269	238,106	13,730	2,675	43,805	61,055
2006	NA	NA	3,293	244,419	13,474	2,692	43,968	61,224
2007	NA	NA	3,273	248,679	13,161	2,740	44,492	61,578
2008	NA	NA	3,124	248,693	12,560	2,766	45,527	60,764
2009	NA	NA	3,123	249,189	12,533	2,644	45,067	58,679
2010	NA	NA	2,780	223,266	12,450	2,262	39,349	57,496
2011	NA	NA	2,827	226,122	12,503	2,311	39,927	57,884
2012	NA	NA	2,892	229,282	12,612	2,373	40,625	58,417
2013	NA	NA	2,962	232,755	12,724	2,434	41,310	58,909
2014	NA	NA	2,789	213,487	13,062	2,313	38,709	59,764
2015	NA	NA	2,841	216,406	13,130	2,359	39,276	60,054
2016	NA	NA	2,891	219,257	13,184	2,402	39,813	60,323
2017	NA	NA	2,938	222,073	13,229	2,446	40,348	60,614
2018	NA	NA	2,984	224,844	13,270	2,490	40,888	60,901
2019	NA	NA	3,030	227,602	13,314	2,535	41,430	61,184

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Power Supply 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
2000	608	1,068	569,360	0	61	121	4,575
2001	602	1,097	548,710	0	55	120	4,632
2002	625	1,125	555,920	0	59	122	5,228
2003	615	1,126	546,214	0	71	120	6,587
2004	629	1,134	554,126	0	71	117	6,618
2005	638	1,163	548,974	0	73	115	6,770
2006	660	1,207	546,916	0	76	107	6,829
2007	673	1,221	551,483	0	75	111	6,872
2008	589	991	594,455	0	74	112	6,665
2009	557	974	571,653	0	75	110	6,509
2010	555	972	570,194	0	73	107	5,776
2011	568	977	581,116	0	75	107	5,888
2012	587	989	592,988	0	76	108	6,036
2013	606	1,012	598,984	0	78	109	6,188
2014	625	1,039	600,996	0	75	110	5,912
2015	641	1,067	601,343	0	76	111	6,029
2016	657	1,093	601,666	0	78	112	6,139
2017	673	1,116	602,823	0	79	113	6,248
2018	689	1,139	604,753	0	80	114	6,356
2019	705	1,162	606,999	0	81	115	6,466

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Power Supply 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
2000	0	262	4,838	0	184,323
2001	0	245	4,877	0	186,902
2002	0	305	5,532	0	207,834
2003	0	421	7,008	0	271,236
2004	0	382	7,000	0	278,639
2005	0	374	7,145	0	283,074
2006	0	382	7,211	0	289,594
2007	0	373	7,246	0	294,392
2008	0	301	6,966	0	295,211
2009	0	349	6,858	0	295,230
2010	0	321	6,097	0	263,588
2011	0	327	6,215	0	267,026
2012	0	335	6,371	0	270,896
2013	0	343	6,531	0	275,077
2014	0	317	6,229	0	253,236
2015	0	323	6,353	0	256,749
2016	0	329	6,468	0	260,162
2017	0	335	6,583	0	263,538
2018	0	341	6,697	0	266,872
2019	0	346	6,812	0	270,194

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 3.1
History and Forecast of Summer Peak Demand (MW) – Base Case
All-Requirements Power Supply 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
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	1,521	0	0	0	0	0	0	0	1,521
2008	1,450	0	0	0	0	0	0	0	1,450
2009	1,483	0	0	0	0	0	0	0	1,483
2010	1,264	0	0	0	0	0	0	0	1,264
2011	1,288	0	0	0	0	0	0	0	1,288
2012	1,321	0	0	0	0	0	0	0	1,321
2013	1,354	0	0	0	0	0	0	0	1,354
2014	1,296	0	0	0	0	0	0	0	1,296
2015	1,322	0	0	0	0	0	0	0	1,322
2016	1,346	0	0	0	0	0	0	0	1,346
2017	1,370	0	0	0	0	0	0	0	1,370
2018	1,394	0	0	0	0	0	0	0	1,394
2019	1,418	0	0	0	0	0	0	0	1,418

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 3.2
History and Forecast of Winter Peak Demand (MW) – Base Case
All-Requirements Power Supply 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
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	1,330	0	0	0	0	0	0	0	1,330
2008/09	1,419	0	0	0	0	0	0	0	1,419
2009/10	1,153	0	0	0	0	0	0	0	1,153
2010/11	1,175	0	0	0	0	0	0	0	1,175
2011/12	1,204	0	0	0	0	0	0	0	1,204
2012/13	1,234	0	0	0	0	0	0	0	1,234
2013/14	1,192	0	0	0	0	0	0	0	1,192
2014/15	1,216	0	0	0	0	0	0	0	1,216
2015/16	1,238	0	0	0	0	0	0	0	1,238
2016/17	1,260	0	0	0	0	0	0	0	1,260
2017/18	1,282	0	0	0	0	0	0	0	1,282
2018/19	1,305	0	0	0	0	0	0	0	1,305

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 3.3
History and Forecast of Annual Net Energy for Load (GWh) – Base Case
All-Requirements Power Supply 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 %
2000	4,575	0	0	4,575	0	262	4,838	57%
2001	4,632	0	0	4,632	0	245	4,877	55%
2002	5,228	0	0	5,228	0	305	5,532	53%
2003	6,587	0	0	6,587	0	421	7,008	54%
2004	6,618	0	0	6,618	0	382	7,000	56%
2005	6,770	0	0	6,770	0	374	7,145	54%
2006	6,829	0	0	6,829	0	382	7,211	56%
2007	6,872	0	0	6,872	0	373	7,246	54%
2008	6,665	0	0	6,665	0	301	6,966	55%
2009	6,509	0	0	6,509	0	349	6,858	53%
2010	5,776	0	0	5,776	0	321	6,097	55%
2011	5,888	0	0	5,888	0	327	6,215	55%
2012	6,036	0	0	6,036	0	335	6,371	55%
2013	6,188	0	0	6,188	0	343	6,531	55%
2014	5,912	0	0	5,912	0	317	6,229	55%
2015	6,029	0	0	6,029	0	323	6,353	55%
2016	6,139	0	0	6,139	0	329	6,468	55%
2017	6,248	0	0	6,248	0	335	6,583	55%
2018	6,356	0	0	6,356	0	341	6,697	55%
2019	6,466	0	0	6,466	0	346	6,812	55%

[1] Amounts shown for 2000 through 2008 represent historical values. Amounts shown for 2009 through 2019 represent forecast values.

Schedule 3.1a
Forecast of Summer Peak Demand (MW) – High Case
All-Requirements Power Supply 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
2010	1,315	0	0	0	0	0	0	0	1,315
2011	1,341	0	0	0	0	0	0	0	1,341
2012	1,374	0	0	0	0	0	0	0	1,374
2013	1,409	0	0	0	0	0	0	0	1,409
2014	1,348	0	0	0	0	0	0	0	1,348
2015	1,375	0	0	0	0	0	0	0	1,375
2016	1,400	0	0	0	0	0	0	0	1,400
2017	1,425	0	0	0	0	0	0	0	1,425
2018	1,450	0	0	0	0	0	0	0	1,450
2019	1,475	0	0	0	0	0	0	0	1,475

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

Schedule 3.2a
Forecast of Winter Peak Demand (MW) – High Case
All-Requirements Power Supply 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
2009/10	1,201	0	0	0	0	0	0	0	1,201
2010/11	1,224	0	0	0	0	0	0	0	1,224
2011/12	1,254	0	0	0	0	0	0	0	1,254
2012/13	1,285	0	0	0	0	0	0	0	1,285
2013/14	1,242	0	0	0	0	0	0	0	1,242
2014/15	1,267	0	0	0	0	0	0	0	1,267
2015/16	1,290	0	0	0	0	0	0	0	1,290
2016/17	1,313	0	0	0	0	0	0	0	1,313
2017/18	1,336	0	0	0	0	0	0	0	1,336
2018/19	1,359	0	0	0	0	0	0	0	1,359

[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 Power Supply 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 %
2010	6,013	0	0	6,013	0	330	6,342	55%
2011	6,128	0	0	6,128	0	336	6,464	55%
2012	6,281	0	0	6,281	0	344	6,626	55%
2013	6,439	0	0	6,439	0	353	6,792	55%
2014	6,153	0	0	6,153	0	326	6,479	55%
2015	6,275	0	0	6,275	0	332	6,607	55%
2016	6,389	0	0	6,389	0	338	6,727	55%
2017	6,502	0	0	6,502	0	344	6,846	55%
2018	6,614	0	0	6,614	0	350	6,964	55%
2019	6,727	0	0	6,727	0	356	7,083	55%

[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 Power Supply 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
2010	1,224	0	0	0	0	0	0	0	1,224
2011	1,247	0	0	0	0	0	0	0	1,247
2012	1,279	0	0	0	0	0	0	0	1,279
2013	1,311	0	0	0	0	0	0	0	1,311
2014	1,255	0	0	0	0	0	0	0	1,255
2015	1,280	0	0	0	0	0	0	0	1,280
2016	1,303	0	0	0	0	0	0	0	1,303
2017	1,327	0	0	0	0	0	0	0	1,327
2018	1,350	0	0	0	0	0	0	0	1,350
2019	1,374	0	0	0	0	0	0	0	1,374

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

Schedule 3.2b
Forecast of Winter Peak Demand (MW) – Low Case
All-Requirements Power Supply 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
2009/10	1,115	0	0	0	0	0	0	0	1,115
2010/11	1,137	0	0	0	0	0	0	0	1,137
2011/12	1,165	0	0	0	0	0	0	0	1,165
2012/13	1,194	0	0	0	0	0	0	0	1,194
2013/14	1,153	0	0	0	0	0	0	0	1,153
2014/15	1,176	0	0	0	0	0	0	0	1,176
2015/16	1,198	0	0	0	0	0	0	0	1,198
2016/17	1,220	0	0	0	0	0	0	0	1,220
2017/18	1,241	0	0	0	0	0	0	0	1,241
2018/19	1,263	0	0	0	0	0	0	0	1,263

[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 Power Supply Project [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2010	5,590	0	0	5,590	0	315	5,905	55%
2011	5,699	0	0	5,699	0	321	6,019	55%
2012	5,842	0	0	5,842	0	329	6,171	55%
2013	5,989	0	0	5,989	0	337	6,326	55%
2014	5,722	0	0	5,722	0	311	6,034	55%
2015	5,836	0	0	5,836	0	317	6,153	55%
2016	5,942	0	0	5,942	0	323	6,265	55%
2017	6,048	0	0	6,048	0	329	6,377	55%
2018	6,153	0	0	6,153	0	334	6,487	55%
2019	6,259	0	0	6,259	0	340	6,599	55%

[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 Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2009		Forecast - 2010		Forecast - 2011	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,406	528	1,153	474	1,175	480
February	1,419	474	1,026	427	1,046	433
March	1,059	495	898	444	915	451
April	1,030	506	960	450	979	457
May	1,271	601	1,108	535	1,130	546
June	1,483	674	1,202	583	1,225	596
July	1,352	687	1,221	608	1,244	619
August	1,382	701	1,264	642	1,288	656
September	1,294	645	1,160	561	1,183	573
October	1,326	611	1,044	499	1,064	510
November	954	472	920	420	943	430
December	975	504	910	454	933	464

Florida Municipal Power Agency

Section 4.0

Renewable Resources and Conservation Programs

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Section 4 Renewable Resources and Demand Side Management Programs

4.1 Introduction

FMPA continually evaluates renewable and demand-side management resource opportunities as part of its integrated resource planning process for the ARP. The ARP currently utilizes renewable energy resources as part of the generation portfolio, including solar photovoltaic (PV) and biomass. In addition, the ARP is pilot testing several Demand Side Management programs, including:

1. Conservation & Energy Efficiency Programs
2. Fuel Switching
3. Load Management

The renewable energy and Demand Side Management programs are presented below.

4.2 Renewable Resources

The following provides an overview of the ARP's current renewable resources, as well as new resources that are being considered as part of FMPA's integrated resource planning process:

4.2.1 Solar Photovoltaic

In December 2009, the ARP completed construction on a 30 kW solar photovoltaic (PV) project located in Key West, FL. This project was developed and constructed as a joint partnership between the National Oceanic and Atmospheric Administration (NOAA) and FMPA. FMPA receives 62% of the energy generated from the solar PV system.

FMPA continues to evaluate additional opportunities for Solar PV projects for the ARP.

4.2.2 Biomass

FMPA currently receives biomass 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 2009, FMPA purchased 13,081 MWh of energy from this renewable resource.

In addition, the ARP receives energy from the ARP's and ARP Participants' shares (25.7% in the aggregate as of December 31, 2009) in the Stanton Energy Center Units 1 and 2 which burns landfill gas as a supplemental fuel source. In 2009 the Stanton Energy Center consumed 861,690 MMbtu of landfill gas, of which 221,815 MMbtu is an energy source for the ARP.

In addition, FMPA continues to hold discussions with biomass developers and evaluate proposals in an effort to find additional cost-effective biomass resources for the ARP.

4.2.3 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. 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 energy from the project under a Power Purchase Agreement. FMPA signed a Letter of Intent with the vender, and is holding discussions with the vendor as the development progress continues.

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

4.3 Demand Side Management Programs

The ARP is currently evaluating and pilot testing several Demand Side Management programs. These programs fall into three general categories:

1. Conservation & Energy Efficiency Programs
2. Fuel Switching
3. Load Management

4.3.1 Conservation & Energy Efficiency Programs

The ARP Participants have developed the ARP Conservation Program to provide conservation and energy efficiency incentives and assistance to their retail customers. The project is funded through the ARP rates and members are allocated funds based on their energy load ratio share. Each ARP Participant can elect to implement programs that are most suitable for their community.

Conservation programs offered by ARP Participants include:

- Rebates on ENERGY STAR® qualified appliances
- Rebates on insulation upgrades and duct leak repair
- Residential and Commercial energy audits
- Customer education materials, including brochures and DVDs
- Equipment and training for utility energy auditors

Since the inception of the program, the ARP Participants have allocated more than $1.5 million to the ARP Conservation Program.

In addition to the ARP Conservation Program, 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 newsletters, posters, bill stuffers, and web banners to participate in the campaigns and promote the conservation message to their customers.

Several ARP Participants also offer their customers an online energy audit service as a link from the city's website through the Energy Depot Online Energy Audit. The online energy audit allows customers to conduct an online energy audit with tailored recommendations for improving energy efficiency in their home. The site also allows customers to estimate annual energy use and cost to operate a complete range of home electric and natural gas systems from HVAC systems to small appliances.

FMPA is currently not including the effects of its energy efficiency programs in its forecast of demand and net energy for load as this program is still in a pilot phase. FMPA is developing reporting tools and techniques in order to be able to verify program effects on demand and NEL and thus develop methods to forecast the effects of this program. To the extent that recent energy efficiency efforts have been captured in actual consumption data for the last one or two years, the effects of the program are included in the current load forecast.

4.3.2 Fuel Switching Programs

In June 2008, the ARP Participants adopted a Net Metering Policy to permit interconnection of customer-owned renewable generation to the distribution system. This policy facilitates the purchase of excess customer-owned renewable generation and outlines the metering, billing and crediting procedures to be followed by ARP Participants. Thus, through the Net Metering Program the ARP has been able to switch the fuel used to provide the energy from certain residential and commercial customer loads from traditional ARP fuel sources to PV. As of December 2009, ARP had approximately 177 kW of solar photovoltaic renewable generation connected to the grid through the Net Metering Program.

As with the energy efficiency programs, FMPA is currently not including the effects of its net metering program in its forecast of demand and net energy for load as this program is still in a pilot phase. However, to the extent that recent net metering program results via reduced customer consumption of utility generated electricity have been captured in actual consumption data for the last one or two years, the effects of the program are included in the current load forecast.

In addition to fuel switching to solar PV, several ARP members also offer rebates on Solar Hot Water Heaters to encourage fuel switching to solar thermal energy.

4.3.3 Load Management Programs

The ARP Participants are currently evaluating options for a Load Management Program. Potential programs could include:

- Identifying backup generation for use for peak shaving efforts;
- Implementing a program to identify and optimize large customer loads; and
- Implementing Time of Use Rates

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Section 5.0

Forecast of Facilities Requirements

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Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's integrated resource planning (IRP) mandate is to assure, on a long-term basis, a low-cost and reliable electricity supply to ARP Participants that reflects the goals and objectives established by the ARP Participants. FMPA's planning process is consistent with Florida Public Service Commission (PSC) statutory and regulatory requirements which do not specifically subject utilities in Florida to integrated resource planning, but when taken together equate to an integrated resource planning requirement. In addition, FMPA's process is considerate of the Public Utility Regulatory Act (PURPA) which requires certain standards of practice to comply with retail rate regulations.

The IRP planning process requires that FMPA and the ARP Executive Committee evaluate alternative resource portfolios and make certain decisions regarding implementing a particular preferred plan. Certain requirements, such as maintaining 18 percent Summer Peak Reserves and 15 percent Winter Peak Reserves on a planned basis, and 'best efforts" goals, such as achieving the lowest net present value cost over the next 20 years, and integrating demand-side and renewable resources into the ARP power supply portfolio, have been developed as guidelines to assist FMPA and the Executive Committee in communicating and evaluating the key issues associated with making resource portfolio planning decisions.

5.2 Planned ARP Generating Facility Requirements

FMPA is currently developing a nominal 300 MW (summer rating), natural gas-fired combined cycle unit at the Cane Island Power Park site jointly owned by FMPA and KUA. Cane Island Unit 4 (CI4) is scheduled for commercial operation in the spring of 2011. In August 2008, the Florida Public Service Commission granted FMPA's petition for determination of need for CI4. The Florida Department of Environmental Protection issued final approval under the Florida Power Plant Siting Act in December 2008. Construction of CI4 began in the spring of 2009.

Schedule 8 at the end of this section shows planned and prospective ARP generating resources additions and changes during the next 10-year period.

5.3 Capacity and Power Purchase Requirements

The current system firm power supply purchase resources of the ARP include purchases from PEF, FPL, and Southern Company. Power purchase contracts including in the ARP plans are briefly summarized below:

- **PEF:** FMPA has a power contract with PEF for partial requirements (PR) services through December 2010. FMPA expects to take 120 MW in 2010. This power purchase includes reserves.
- **FPL:** FMPA has a long-term purchase contract with FPL for 45 MW until June 2013. The FPL long-term purchase includes reserves.
- **Southern Company:** FMPA has a contract for 79 MW (summer rating) of purchase power, including KUA's share, from Southern Power's Stanton A combined cycle that extends to 2023 and has various extension options. FMPA also has a contract for approximately 160 MW (summer rating) of peaking capacity from Southern Power's Oleander plant which began in December 2007 and has a term of 20 years.
- **Seasonal Peaking Purchase:** FMPA is currently planning to meet its additional capacity requirements in the summer of 2019 with a capacity purchase from a supplier to be determined.

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 Power Supply Project Resource Summer Capacity

Line No.	Resource Description	Summer Rating (MW)									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	74	74	80	84	64	64	64	64	64	64
2	Stanton Coal Plant	185	185	185	185	175	175	175	175	175	175
3	Stanton CC Unit A	42	42	42	42	42	42	42	42	42	42
4	Cane Island 1-3	368	368	368	368	368	368	368	368	368	368
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	Treasure Coast Energy Center	300	300	300	300	300	300	300	300	300	300
9	Key West Native Generation	31	31	31	31	31	31	31	31	31	31
10	Kissimmee Native Generation	44	44	44	44	44	-	-	-	-	-
11	Lake Worth Native Generation	88	88	88	88	-	-	-	-	-	-
12	Sub Total Existing Resources	1,289	1,290	1,296	1,300	1,180	1,137	1,137	1,137	1,137	1,137
	Planned Additions										
13	Cane Island 4	-	300	300	300	300	300	300	300	300	300
15	Sub Total Planned Additions	-	300	300	300	300	300	300	300	300	300
16	**Total Installed Capacity**	**1,289**	**1,590**	**1,596**	**1,600**	**1,480**	**1,437**	**1,437**	**1,437**	**1,437**	**1,437**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
17	Stanton A Purchase	79	79	79	79	79	79	79	79	79	79
18	Oleander Purchase	160	160	160	160	160	160	160	160	160	160
19	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	30
20	Sub Total Without Reserves	239	239	239	239	239	239	239	239	239	269
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	120	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	45	45	-	-	-	-	-	-	-
23	Sub Total With Reserves	165	45	45	-	-	-	-	-	-	-
24	**Total Firm Capacity Import**	**404**	**284**	**284**	**239**	**239**	**239**	**239**	**239**	**239**	**269**
25	**Total Available Capacity**	**1,692**	**1,873**	**1,879**	**1,838**	**1,719**	**1,676**	**1,676**	**1,676**	**1,676**	**1,706**

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

Line No.	Resource Description	Winter Rating (MW)									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	75	76	82	86	65	65	65	65	65	65
2	Stanton Coal Plant	186	186	186	186	175	175	175	175	175	175
3	Stanton CC Unit A	45	45	45	45	45	45	45	45	45	45
4	Cane Island 1-3	382	382	382	382	382	382	382	382	382	382
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	Treasure Coast Energy Center	310	310	310	310	310	310	310	310	310	310
9	Key West Native Generation	31	31	31	31	31	31	31	31	31	31
10	Kissimmee Native Generation	45	45	45	45	45	-	-	-	-	-
11	Lake Worth Native Generation	92	92	92	92	-	-	-	-	-	-
12	Sub Total Existing Resources	1,343	1,343	1,350	1,354	1,230	1,185	1,185	1,185	1,185	1,185
	Planned Additions										
13	Cane Island 4	-	-	310	310	310	310	310	310	310	310
15	Sub Total Planned Additions	-	-	310	310	310	310	310	310	310	310
16	**Total Installed Capacity**	**1,343**	**1,343**	**1,660**	**1,664**	**1,540**	**1,495**	**1,495**	**1,495**	**1,495**	**1,495**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
17	Stanton A Purchase	84	84	84	84	84	84	84	84	84	84
18	Oleander Purchase	180	180	180	180	180	180	180	180	180	180
19	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
20	Sub Total Without Reserves	264	264	264	264	264	264	264	264	264	264
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	120	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	45	45	45	-	-	-	-	-	-
23	Sub Total With Reserves	165	45	45	45	-	-	-	-	-	-
24	**Total Firm Capacity Import**	**429**	**309**	**309**	**309**	**264**	**264**	**264**	**264**	**264**	**264**
25	**Total Available Capacity**	**1,771**	**1,652**	**1,968**	**1,972**	**1,804**	**1,759**	**1,759**	**1,759**	**1,759**	**1,759**

Schedule 5
Fuel Requirements – All-Requirements Power Supply Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Fuel Type	Unit Type	Fuel Units	Actual 2009	Forecasted 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	Nuclear [1]		Trillion BTU	7	6	6	6	6	5	5	5	5	5	4
2	Coal		000 Ton	589	521	471	485	526	499	507	509	485	445	410
	Residual													
3		Steam	000 BBL	-	4	5	5	6	7	3	4	4	5	4
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	4	5	5	6	7	3	4	4	5	4
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	16	9	15	24	37	45	51	57	65	75	79
10		Total	000 BBL	16	9	15	24	37	45	51	57	65	75	79
	Natural Gas													
11		Steam	000 MCF	470	-	-	4	4	-	-	-	-	-	-
12		CC	000 MCF	30,919	21,477	30,166	34,080	34,044	33,826	34,342	35,252	38,658	40,749	43,741
13		CT	000 MCF	560	42	75	68	75	92	39	85	150	211	192
14		Total	000 MCF	31,949	21,520	30,241	34,153	34,123	33,918	34,381	35,337	38,808	40,960	43,934
	Renewables [2]													
15		Biofuels	Billion BTU	131	131	131	131	131	131	131	131	131	131	131
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hyrdro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	222	222	203	189	174	155	146	137	128	119	110
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	353	353	334	319	305	286	277	268	259	250	241
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-

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

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Energy Source	Prime Mover	Units	Actual 2009	Forecasted 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	644	576	570	595	548	447	425	435	425	447	410
3	Coal		GWh	1,499	1,327	1,201	1,236	1,340	1,269	1,290	1,293	1,234	1,133	1,036
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	8	5	8	12	18	22	25	28	33	38	41
11		Total	GWh	8	5	8	12	18	22	25	28	33	38	41
	Natural Gas													
12		Steam	GWh	24	-	-	0	0	-	-	-	-	-	-
13		CC	GWh	3,902	2,960	3,934	4,298	4,348	4,277	4,376	4,443	4,678	4,901	5,196
14		CT	GWh	49	4	7	6	7	8	3	7	13	19	17
15		Total	GWh	3,975	2,963	3,941	4,304	4,355	4,285	4,379	4,450	4,691	4,919	5,213
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [2]													
17		Biofuels	GWh	13	13	13	13	13	13	13	13	13	13	13
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	22	23	21	19	18	16	15	14	13	12	11
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	35	36	34	33	31	29	28	27	26	25	24
27	Interchange		GWh	736	1,252	578	311	360	293	323	354	295	258	212
28	Net Energy for Load [3]		GWh	6,897	6,159	6,331	6,491	6,652	6,346	6,470	6,588	6,704	6,820	6,937

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	9.3	9.4	9.0	9.2	8.2	7.1	6.6	6.6	6.3	6.6	5.9
3	Coal		%	21.7	21.5	19.0	19.0	20.1	20.0	19.9	19.6	18.4	16.6	14.9
	Residual													
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6
11		Total	%	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6
	Natural Gas													
12		Steam	%	0.3	-	-	0.0	0.0	-	-	-	-	-	-
13		CC	%	56.6	48.0	62.1	66.2	65.4	67.4	67.6	67.4	69.8	71.9	74.9
14		CT	%	0.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2
15		Total	%	57.6	48.1	62.2	66.3	65.5	67.5	67.7	67.6	70.0	72.1	75.1
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
	Renewables [2]													
17		Biofuels	%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
18		Biomass	%	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	%	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	%	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	%	0.3	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
22		MSW	%	-	-	-	-	-	-	-	-	-	-	-
23		Solar	%	-	-	-	-	-	-	-	-	-	-	-
24		Wind	%	-	-	-	-	-	-	-	-	-	-	-
25		Other	%	-	-	-	-	-	-	-	-	-	-	-
26		Total	%	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
27	Interchange		%	10.7	20.3	9.1	4.8	5.4	4.6	5.0	5.4	4.4	3.8	3.1
28	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 ARP 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 Power Supply Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin before Maintenance [3]			Reserve Margin after Maintenance [3]	
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Summer Peak Demand (MW) [2]	(MW)	(% of Peak)	Scheduled Maintenance (MW)	(MW)	(% of Peak)
2010	1,289	404	0	0	1,692	1,279	414	37%	0	414	37%
2011	1,590	284	0	0	1,873	1,313	561	44%	0	561	44%
2012	1,596	284	0	0	1,879	1,346	534	41%	0	534	41%
2013	1,600	239	0	0	1,838	1,380	458	33%	0	458	33%
2014	1,480	239	0	0	1,719	1,320	399	30%	0	399	30%
2015	1,437	239	0	0	1,676	1,346	329	24%	0	329	24%
2016	1,437	239	0	0	1,676	1,371	305	22%	0	305	22%
2017	1,437	239	0	0	1,676	1,395	280	20%	0	280	20%
2018	1,437	239	0	0	1,676	1,420	256	18%	0	256	18%
2019	1,437	269	0	0	1,706	1,445	261	18%	0	261	18%

[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 Power Supply 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 Winter Peak Demand	Reserve Margin before Maintenance [3]		Scheduled Maintenance	Reserve Margin after Maintenance [3]	
Year	(MW) [1]	(MW) [1]	(MW)	QF (MW)	(MW)	(MW) [2]	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2009/10	1,343	429	0	0	1,771	1,167	604	60%	0	604	60%
2010/11	1,343	309	0	0	1,652	1,198	455	39%	0	455	39%
2011/12	1,660	309	0	0	1,968	1,227	741	63%	0	741	63%
2012/13	1,664	309	0	0	1,972	1,258	715	59%	0	715	59%
2013/14	1,540	264	0	0	1,804	1,215	589	48%	0	589	48%
2014/15	1,495	264	0	0	1,759	1,239	520	42%	0	520	42%
2015/16	1,495	264	0	0	1,759	1,262	497	39%	0	497	39%
2016/17	1,495	264	0	0	1,759	1,284	474	37%	0	474	37%
2017/18	1,495	264	0	0	1,759	1,307	452	35%	0	452	35%
2018/19	1,495	264	0	0	1,759	1,329	429	32%	0	429	32%

[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														
Cane Island	CC4	Osceola	CC	NG	-	PL	-	NA	05/11	NA	NA	300	310	V
Changes to Existing Resources														
Municipal Plant (Vero Beach)	1	Indian River	ST	NG	RFO	PL	TK	NA	01/10	NA	NA	(11)	(12)	OT [1]
Municipal Plant (Vero Beach)	2	Indian River	CA	WH	-	-	-	NA	01/10	NA	NA	(12)	(11)	OT [1]
Municipal Plant (Vero Beach)	3	Indian River	ST	NG	RFO	PL	TK	NA	01/10	NA	NA	(32)	(33)	OT [1]
Municipal Plant (Vero Beach)	4	Indian River	ST	NG	RFO	PL	TK	NA	01/10	NA	NA	(51)	(53)	OT [1]
Municipal Plant (Vero Beach)	5	Indian River	CT	NG	RFO	PL	TK	NA	01/10	NA	NA	(32)	(35)	OT [1]
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	NA	01/10	NA	NA	(21)	(21)	OT [1]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	NA	01/10	NA	NA	(17)	(17)	OT [1]
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	01/10	NA	NA	(11)	(11)	OT [1]
Crystal River	3	Citrus	NP	UR	-	TK	-	NA	09/10	NA	NA	1	1	A
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	12/11	NA	NA	6	6	A
Crystal River	3	Citrus	NP	UR	-	TK	-	NA	11/12	NA	NA	4	4	A
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	NA	01/14	NA	NA	(10)	(10)	OT [2]
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	01/14	NA	NA	(21)	(21)	OT [2]
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	NA	01/14	NA	NA	(26)	(27)	OT [2]
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	NA	01/14	NA	NA	(20)	(21)	OT [2]
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [2]
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [2]
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [2]
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [2]
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [2]
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	NA	01/14	NA	NA	(24)	(25)	OT [2]
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	NA	01/14	NA	NA	(8)	(9)	OT [2]
Hansel Plant	21	Osceola	CT	NG	-	PL	-	NA	02/83	12/14	38	(28)	(34)	RT
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	12/14	8	(8)	(5)	RT
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	12/14	8	(8)	(5)	RT

[1] The City of Vero Beach has exercised the right to modify its ARP full requirements membership. Effective January 1, 2010, the ARP will no longer utilize Vero Beach's generating resources, including its entitlement shares in the Stanton, Stanton II, and St. Lucie Projects.

[2] The City of Lake Worth has provided notice to FMPA that it will exercise the right to modify its ARP full requirements membership. Effective January 1, 2014, the ARP will no longer utilize Lake Worth's generating resources, including its entitlement shares in the Stanton and St. Lucie Projects.

Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

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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.

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

FMPA anticipates that simple cycle combustion turbines could be installed at an ARP Participant owned generation site, such as the Stock Island site at KEYS, 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 the Treasure Coast Energy Center site. FMPA continuously explores the feasibility of other sites located within Florida with the expectation that ARP Participant cities would provide the best option for future development.

Cane Island Power Park

Cane Island Power Park is located south and west of KUA's service area and contains 368 MW (summer ratings) 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. FMPA is currently constructing CI4, a nominal 300 MW (summer rating), natural gas-fired 1x1 GE 7FA combined cycle unit. CI4 is scheduled for commercial operation in the spring of 2011.

Treasure Coast Energy Center

FMPA commissioned Treasure Coast Energy Center (TCEC) Unit 1, a dual fuel low sulfur diesel and natural gas-fired 300 MW (summer rating) 1x1 GE 7FA combined cycle unit in May 2008. 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.

Stock Island

The Stock Island site currently consists of four combustion turbines and two diesel generating units. Three additional diesel units owned by KEYS at the Stock Island site were retired in December 2009. 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.

Schedule 9 presents the status report and specifications for the proposed ARP generating facility. Schedule 10 contains the status report and specifications for proposed ARP transmission line projects.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities
All-Requirements Power Supply Project
(Preliminary Information)

(1)	Plant Name and Unit Number	Cane Island Unit 4
(2)	Capacity	
	a. Summer	300
	b. Winter	310
(3)	Technology Type	CC (1x1 GE 7FA)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	May-09
	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	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	94.2%
	Resulting Capacity Factor	69.3%
	Average Net Operating Heat Rate (ANOHR)	7,171 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,475
	Direct Construction Cost (2010 $/kW)	$1,331
	AFUDC Amount ($/kW) [1]	$109
	Escalation ($/kW)	$35
	Fixed O&M ($/kW)	4.56 $/kW-yr
	Variable O&M ($/MWh)	$3.30

[1] Includes AFUDC and bond issuance expenses

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

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

Note: FMPA currently has no new proposed transmission lines.

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Appendix I

List of Abbreviations

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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
A	Generation Unit Capability Increased
OT	Other

Other

NA	Not Available or Not Applicable

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Appendix II

ARP Participant Transmission Information

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Appendix II
ARP Participant Transmission Information

Table II-1 presented on the following page contains a list of planned and proposed transmission line additions for ARP Participant cities.

Table II-1
Planned and Proposed Transmission Additions for ARP Participants
2010 through 2019 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Ft. Pierce	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	1	9/2016
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	2	9/2016
	Southwest Substation			138/13.2 kV		9/2016
Kissimmee	Cane Island (Reconductor)	Tie Point (Taft)		230 kV	1	4/2010
	Cane Island (Reconductor)	Tie Point (Osceola)		230 kV	1	4//2010
	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
	C.A.Wall	Turnpike		69 kV	1	6/2015
	Domingo Toro Substation			69 kV		6/2015
	Domingo Toro Substation	Tie Point with St.Cloud		69 kV	1	6/2015
	Osceola Parkway Substation			69 kV		6/2015
	Lake Bryan	Osceola Parkway		69 kV	1	6/2015
	Lake Cecile	Osceola Parkway		69 kV	1	6/2015
Ocala	Dearmin / Baseline Substation (Improvements)			69 kV		9/2010
	Ergle Substation Third Breaker			69 kV		12/2010
	Ergle	Silver Springs		69 kV	1	12/2010
	Dearmin	Baseline Rd		69 kV	1	12/2010
	Shaw Second 30 MVA Transformer		30	69/12.47 kV	1	6/2017

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Appendix III

Additional Reserve Margin Information

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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 Power Supply 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)
2010	1,692	1,279	165	414	37%
2011	1,873	1,313	45	561	44%
2012	1,879	1,346	45	534	41%
2013	1,838	1,380	0	458	33%
2014	1,719	1,320	0	399	30%
2015	1,676	1,346	0	329	24%
2016	1,676	1,371	0	305	22%
2017	1,676	1,395	0	280	20%
2018	1,676	1,420	0	256	18%
2019	1,706	1,445	0	261	18%

[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 Power Supply 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)
2009/10	1,771	1,167	165	604	60%
2010/11	1,652	1,198	45	455	39%
2011/12	1,968	1,227	45	741	63%
2012/13	1,972	1,258	45	715	59%
2013/14	1,804	1,215	0	589	48%
2014/15	1,759	1,239	0	520	42%
2015/16	1,759	1,262	0	497	39%
2016/17	1,759	1,284	0	474	37%
2017/18	1,759	1,307	0	452	35%
2018/19	1,759	1,329	0	429	32%

[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)

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