FMPA

Florida Municipal Power Agency

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

110000-OT

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

Re: FMPA's 2011 Ten Year Site Plan

March 30, 2011

Dear Sir/Madam:

Pursuant to Rule 25-22.071(1) Florida Administrative Code, FMPA is hereby submitting 25 copies of its 2011 Ten Year Site Plan. If you have any questions, please do not hesitate to contact me at (321) 239-1013.

Sincerely,

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

cc. File

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Florida Municipal Power Agency

110000-OT

Ten-Year Site Plan

April 2011

Community Power + Statewide Strength ®

Florida Municipal Power Agency

Ten-Year Site Plan 2011-2020

Submitted to

Florida Public Service Commission

April 1, 2011

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Table of Contents

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Table of Contents

List of Figures, Tables and Required Schedules

Appendices

Florida Municipal Power Agency

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 to participate 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 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 2011 is 1,891 MW. This capacity is comprised of ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements, and is summarized below in Table ES-1.

Table ES-1
FMPA ARP Summer 2011 Capacity Resources

Resource Category	Summer Capacity (MW)
Nuclear	74
ARP Ownership	1,126
ARP Participant Ownership	405
Power Purchases	286
Net Total 2011 ARP Resources	1,891

The ARP is currently constructing a new resource: Cane Island Unit 4 (CI4), a nominal 300 MW (summer rating) combined cycle unit located at the Cane Island Power Park in Osceola County, is currently expected to begin commercial operation in May 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 the ARP's 2011 Load Forecast, the addition of CI4 will allow the ARP to meet its generation capacity requirements until 2020. The projected peak native ARP summer load for 2011 is 1,274 MW and is forecast to increase to 1,418 MW in 2020. At this time, FMPA is planning to meet the ARP's need for additional generation capacity in 2020 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.

In 2010, FMPA, on behalf of the ARP, responded to a Request for Proposals from the City of Quincy for providing full-requirements capacity and energy beyond Quincy's entitlement in a Southeastern Power Administration (SEPA) Project. The ARP was awarded the Quincy contract for the term of January 1, 2011 through December 31, 2015. The ARP is expecting to provide a peak requirement of 26MW to Quincy above its SEPA entitlement during the summer of 2011. The sale to Quincy increases the projected ARP load to 1,300 MW for the summer of 2011.

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, the ARP 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, the ARP commissioned its first solar photovoltaic system, a jointly-owned 30 kW DC system located in Key West, FL. In addition, ARP-Participants are engaged in an ARP-sponsored energy conservation program and several ARP-Participants are piloting Demand Side Management programs aimed at load management.

A location map of the ARP Participants and FMPA's power resources as of January 1, 2011 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 the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes and the supplemental authority granted by the Joint Power Act, Part II, Chapter 361, Florida Statutes, implementing Article VII, Section 10 of the Florida Constitution.

The Interlocal Cooperation Act of 1969 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 supplemental authority for municipal electric utilities to join together with public utilities, electric cooperatives, foreign public utilities and other persons, as defined, for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants.

Each city commission and council, 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.

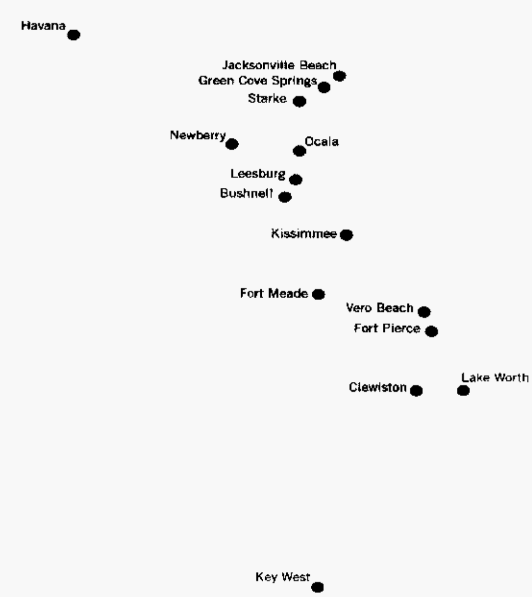
Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP Participants. The ARP began delivering capacity and energy to these original five participants in 1986. The remaining 10 ARP Participants joined as follows:

- 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 resources, or entitlements and/or ownership shares in FMPA power supply projects or third-party developed power plants sell the electric capacity and energy of their resource entitlements and ownership shares to the ARP pursuant to a Capacity & Energy Sales Agreement between FMPA and the ARP Participant, and receive capacity and energy (C&E) credits on their ARP bills.

[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 was going exercise the right to modify its ARP full requirements membership and request and establish a Contract Rate of Delivery (CROD) which began January 1, 2010. 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 and establish a CROD beginning January 1, 2014. In addition, on July 14, 2009 the City of Fort Meade provided notice to FMPA that it will also exercise its right to modify its full requirements membership and establish a CROD beginning January 1, 2015. The effect of these notices is that the ARP will no longer utilize these ARP Participant's generating resources (if any), and the ARP will commence serving the load of these ARP Participants 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 and Fort Meade served by the ARP will be established in 2013 and 2014, respectively.

A brief description of each of the ARP Participants begins on the following page.

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 Roy Trotter 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, CEO, 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. Matthew J. Brower is the City Manager, and Larry M. Novak 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. 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 Other FMPA Power Supply Projects

In addition to the ARP, FMPA facilitates the participation of FMPA Members in four other 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. 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, and FMPA purchased from OUC 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, 2011.

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 exercised the right to modify its ARP full requirements membership (CROD).

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 ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements. The supply side resources for the ARP for the 2011 summer season are shown by ownership capacity in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2011

Resource Category	Summer Capacity (MW)
1) Nuclear	74
2) ARP Ownership	
Existing	825
New [1]	300
Sub Total ARP Ownership	1,125
3) Participant Ownership	
KEYS	31
KUA	285
Lake Worth	88
Sub Total Participant Ownership	405
4) Power Purchases	286
Total 2011 ARP Resources	1,891

[1] Cane Island Unit 4's anticipated Commercial Operation Date is May 2011

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

1) **Nuclear Generation:** A number of the ARP Participants own capacity in Progress Energy Florida's Crystal River Unit 3. Likewise, a number of ARP Participants participate in FMPA's St. Lucie Project, and are entitled to capacity and energy shares 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 their ownership and/or entitlement in 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 wholly owned and operated by FMPA as agent for the ARP, specifically, Treasure Coast Energy Center, Stock Island Generating Facility, and the (soon to be commercial) Cane Island Unit 4. This category also includes ownership shares that the ARP acquired in OUC's Stanton Units 1 and 2, OUC's Indian River Power Plant Units A through D, KUA's Cane Island Units 1-3 and Southern Company's Stanton Unit A. Lastly, this category includes generation entitlements assigned to the ARP by ARP Participants via their participation in other FMPA Power Supply Projects.

3) **Participant Owned Generation:** Capacity included in this category is generation wholly owned by the ARP Participants. The ARP purchases this capacity through Capacity and Energy Sales Agreements between FMPA and the ARP Participants, and then commits and economically dispatches this 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 used to serve the ARP as of January 1, 2011 includes capacity and energy purchased from FPL and Southern Company.

Information regarding existing ARP generation resources as of December 31, 2010, 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. Peninsular 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 Participants are interconnected to the transmission systems of FPL, PEF, OUC, JEA, Seminole Electric Cooperative, Florida Keys Electric Cooperative Association (FKEC), and Tampa Electric Company (TECO). Some ARP Participants own transmission facilities within their service territories, and the ARP has an ownership share of the transmission facilities associated with the Cane Island Power Plant.

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. Sales to the City of Quincy are made across PEF's transmission system.

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' 230kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs North Switching Station. OUS' Dearmin Substation ties at PEF's Silver Springs Switching Station and OUS' 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 and 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 associated with ARP-Participants' or the ARP's entitlements in, ownership shares of or purchases from power plants interconnected to OUC's transmission system, including Stanton Unit 1, Stanton Unit 2, Stanton A combined cycle (CC), and the Indian River combustion turbine (CT) units, to the FPL and PEF interfaces for subsequent delivery to ARP Participants. Rates for such transmission wheeling service for the Stanton and Indian River units are pursuant to the terms and conditions of Firm Transmission Service Agreements between the ARP Participants, or the ARP, and OUC, and rates for transmission service for wheeling service for Stanton A are pursuant to OUC's OATT.

FMPA also has contracts with PEF and FPL for Network Integration Transmission Service that allow FMPA to integrate its resources to serve its load (those loads interconnected with either FPL or PEF) in a manner comparable to how FPL and PEF integrate resources to serve FPL and PEF native loads. The Network Service and Network Operating Agreements with FPL were executed in March 1996 and were subsequently amended to both conform to FERC's Pro forma Tariff and to add additional ARP Participants as points of delivery. The Network Service and Network Operating Agreements with PEF were executed and filed with FERC in January 2011.

Schedule 1
Existing Generating Facilities as of December 31, 2010

(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	26	26
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	49	50
Total Nuclear Capacity											74	76
ARP Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	81	81
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	84	84
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	14	18
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	14	18
Indian River	CT C	Brevard	GT	NG	DFO	PL	TK	08/92	NA	112	22	26
Indian River	CT D	Brevard	GT	NG	DFO	PL	TK	10/92	NA	112	22	26
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	18
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	56
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	120	125
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											825	861
Participant Owned Generation												
Kissimmee Utility Authority												
Hansel Plant	21	Osceola	CT	NG	-	PL	-	02/83	09/14	38	28	34
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	09/14	8	8	5
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	09/14	8	8	5
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	18
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	54	56
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	120	125

Schedule 1 (Continued)
Existing Generating Facilities as of December 31, 2010

(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 (cont.)												
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											285	299
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 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											405	422
Total Generation Resources											1,304	1,359

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

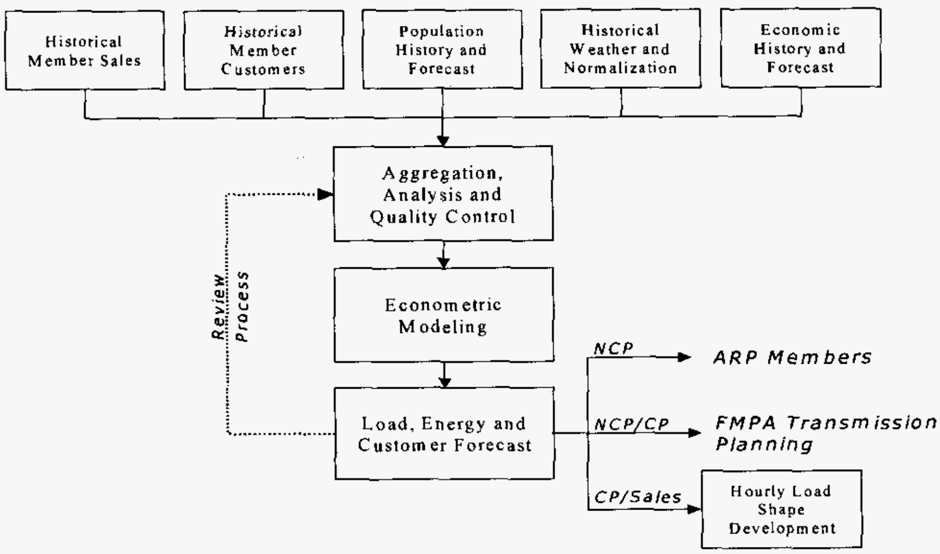
3.1 Introduction

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, with updates during the year if warranted. 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 Participant 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



Note:

NCP is the Non-Coincident Peak demand, which represents the maximum hourly demand for a participant in a given month. CP is the Coincident Peak demand which represents the maximum hourly demand of the ARP system in aggregate, or the hourly demand of the ARP Participant at the time of the ARP CP.

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 2011 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2011 through 2030. 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 IHS Global Insight 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 Participant. 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 Lake Worth's establishment of Contract Rate of Delivery (CROD). 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 potential partial requirements load referred to in Section 1.2 of this document that will 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 Specifications

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 certain large non-residential customers, the forecast was based on assumptions developed in consultation with the Participants (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 1998-2010.

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 (2006-2010). 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 2010 (Study Period). Data included historical customer counts, sales, and revenues by rate classification for each of the ARP Participants.

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 of weather on electricity sales 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

IHS Global Insight 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 1.1% from 2011-2020, and at 1.7% from 2021-2030. The Base Case 2011 ARP forecast summer peak demand is 1,274 MW and forecast annual NEL for Calendar Year 2011 is 6,150 GWh. (These values do not include the Quincy Sale.)

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.

As a general note, the ARP provides wholesale power to the ARP Participants who, in turn, serve retail load. In addition, the ARP has entered into a wholesale power contract to provide full requirements capacity and energy to the City of Quincy, as a wholesale customer of the ARP. The Schedules 2.1 through 4 have been footnoted to properly identify that the reported demands and energy are at the "city gate" of each ARP Participant and the City of Quincy. For example, Schedules 2.1 – 2.3 reflect the energy consumption of the retail customers of the ARP Participants and a sale-for-resale to the City of Quincy which, when combined with utility use and losses within each ARP Participant, represents the NEL that the ARP delivers on an aggregated basis to each city gate.

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
2001	NA	NA	2,098	156,318	13,423	1,744	28,829	60,497
2002	NA	NA	2,405	173,842	13,836	1,990	32,257	61,699
2003	NA	NA	3,168	227,562	13,922	2,600	41,973	61,956
2004	NA	NA	3,182	234,097	13,592	2,635	42,863	61,470
2005	NA	NA	3,252	238,012	13,664	2,668	43,741	61,000
2006	NA	NA	3,308	243,795	13,568	2,684	43,851	61,217
2007	NA	NA	3,272	248,376	13,172	2,721	44,436	61,231
2008	NA	NA	3,142	248,711	12,633	2,775	45,563	60,909
2009	NA	NA	3,153	248,725	12,677	2,681	45,078	59,466
2010	NA	NA	2,941	220,770	13,321	2,280	39,250	58,101
2011	NA	NA	2,801	223,005	12,558	2,305	39,880	57,808
2012	NA	NA	2,855	225,524	12,661	2,343	40,369	58,028
2013	NA	NA	2,921	229,084	12,752	2,384	40,831	58,392
2014	NA	NA	2,756	210,415	13,096	2,261	38,239	59,131
2015	NA	NA	2,813	213,706	13,164	2,307	38,747	59,541
2016	NA	NA	2,869	216,761	13,234	2,353	39,251	59,942
2017	NA	NA	2,923	219,621	13,308	2,398	39,747	60,329
2018	NA	NA	2,977	222,389	13,386	2,443	40,234	60,709
2019	NA	NA	3,032	225,071	13,471	2,489	40,730	61,110
2020	NA	NA	3,088	227,708	13,560	2,537	41,234	61,520

[1] Amounts shown for 2001 through 2010 represent historical values. Amounts shown for 2011 through 2020 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
2001	602	1,097	548,710	0	55	120	4,619
2002	625	1,125	555,920	0	58	122	5,200
2003	615	1,126	546,214	0	69	120	6,573
2004	629	1,134	554,126	0	71	117	6,633
2005	638	1,163	548,974	0	73	115	6,747
2006	660	1,207	546,916	0	76	107	6,836
2007	673	1,221	551,483	0	75	111	6,852
2008	589	991	594,455	0	73	112	6,692
2009	554	960	577,380	0	75	111	6,574
2010	547	993	550,558	0	70	107	5,945
2011	554	1,006	550,712	0	70	109	5,839
2012	565	1,013	557,681	0	71	110	5,943
2013	575	1,027	560,378	0	72	111	6,063
2014	587	1,044	562,251	0	69	111	5,784
2015	599	1,063	564,161	0	70	112	5,902
2016	612	1,083	565,281	0	72	113	6,018
2017	625	1,104	565,898	0	73	114	6,132
2018	638	1,126	566,310	0	74	115	6,246
2019	651	1,148	567,003	0	75	116	6,362
2020	664	1,170	567,803	0	76	117	6,482

[1] Amounts shown for 2001 through 2010 represent historical values. Amounts shown for 2011 through 2020 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 [2]	Utility Use & Losses GWh	Net Energy for Load GWh [2]	Other Customers (Average No.)	Total No. of Customers
2001	0	244	4,863	0	186,244
2002	0	294	5,494	0	207,224
2003	0	421	6,994	0	270,660
2004	0	391	7,024	0	278,094
2005	0	375	7,122	0	282,916
2006	0	378	7,213	0	288,853
2007	0	377	7,229	0	294,033
2008	0	303	6,994	0	295,265
2009	0	340	6,914	0	294,763
2010	0	354	6,299	0	261,014
2011	116	311	6,266	0	263,891
2012	118	316	6,377	0	266,906
2013	120	322	6,505	0	270,942
2014	122	294	6,200	0	249,698
2015	124	300	6,325	0	253,515
2016	0	306	6,324	0	257,095
2017	0	311	6,444	0	260,472
2018	0	317	6,563	0	263,749
2019	0	323	6,686	0	266,949
2020	0	329	6,811	0	270,112

[1] Amounts shown for 2001 through 2010 represent historical values. Amounts shown for 2011 through 2020 represent forecast values.

[2] Years 2011 through 2015 include expected sales to the City of Quincy.

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)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	ARP Net Firm
Year [1]	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2001	962	962	0	0	0	0	0	0	0	962
2002	1,201	1,201	0	0	0	0	0	0	0	1,201
2003	1,343	1,343	0	0	0	0	0	0	0	1,343
2004	1,416	1,416	0	0	0	0	0	0	0	1,416
2005	1,524	1,524	0	0	0	0	0	0	0	1,524
2006	1,478	1,478	0	0	0	0	0	0	0	1,478
2007	1,521	1,521	0	0	0	0	0	0	0	1,521
2008	1,450	1,450	0	0	0	0	0	0	0	1,450
2009	1,482	1,482	0	0	0	0	0	0	0	1,482
2010	1,272	1,272	0	0	0	0	0	0	0	1,272
2011	1,300	1,274	26	0	0	0	0	0	0	1,300
2012	1,323	1,297	26	0	0	0	0	0	0	1,323
2013	1,350	1,323	27	0	0	0	0	0	0	1,350
2014	1,290	1,263	27	0	0	0	0	0	0	1,290
2015	1,317	1,289	28	0	0	0	0	0	0	1,317
2016	1,315	1,315	0	0	0	0	0	0	0	1,315
2017	1,340	1,340	0	0	0	0	0	0	0	1,340
2018	1,366	1,366	0	0	0	0	0	0	0	1,366
2019	1,392	1,392	0	0	0	0	0	0	0	1,392
2020	1,418	1,418	0	0	0	0	0	0	0	1,418

[1] Amounts shown for 2001 through 2010 represent historical values. Amounts shown for 2011 through 2020 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 ARP	Wholesale Quincy	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	ARP Net Firm Demand
2000/01	1,008	1,008	0	0	0	0	0	0	0	1,008
2001/02	1,008	1,008	0	0	0	0	0	0	0	1,008
2002/03	1,473	1,473	0	0	0	0	0	0	0	1,473
2003/04	1,194	1,194	0	0	0	0	0	0	0	1,194
2004/05	1,340	1,340	0	0	0	0	0	0	0	1,340
2005/06	1,401	1,401	0	0	0	0	0	0	0	1,401
2006/07	1,202	1,202	0	0	0	0	0	0	0	1,202
2007/08	1,330	1,330	0	0	0	0	0	0	0	1,330
2008/09	1,419	1,419	0	0	0	0	0	0	0	1,419
2009/10	1,412	1,412	0	0	0	0	0	0	0	1,412
2010/11	1,258	1,258	0	0	0	0	0	0	0	1,258
2011/12	1,226	1,202	25	0	0	0	0	0	0	1,202
2012/13	1,251	1,226	25	0	0	0	0	0	0	1,226
2013/14	1,208	1,182	26	0	0	0	0	0	0	1,182
2014/15	1,233	1,207	26	0	0	0	0	0	0	1,207
2015/16	1,231	1,231	0	0	0	0	0	0	0	1,231
2016/17	1,255	1,255	0	0	0	0	0	0	0	1,255
2017/18	1,279	1,279	0	0	0	0	0	0	0	1,279
2018/19	1,303	1,303	0	0	0	0	0	0	0	1,303
2019/20	1,327	1,327	0	0	0	0	0	0	0	1,327

[1] Amounts shown for 2000/01 through 2010/11 represent historical values. Amounts shown for 2011/12 through 2019/20 represent forecast values. The Actual Winter 2010/2011 peak occurred in December 2010, prior to the Quincy Sale.

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 [2]	Wholesale [3]	Utility Use & Losses	ARP Net Energy for Load [4]	Load Factor %
2001	4,619	0	0	4,619	0	244	4,863	55%
2002	5,200	0	0	5,200	0	294	5,494	52%
2003	6,573	0	0	6,573	0	421	6,994	54%
2004	6,633	0	0	6,633	0	391	7,024	57%
2005	6,747	0	0	6,747	0	375	7,122	53%
2006	6,836	0	0	6,836	0	378	7,213	56%
2007	6,852	0	0	6,852	0	377	7,229	54%
2008	6,692	0	0	6,692	0	303	6,994	55%
2009	6,574	0	0	6,574	0	340	6,914	53%
2010	5,945	0	0	5,945	0	354	6,299	51%
2011	5,839	0	0	5,839	116	311	6,266	56%
2012	5,943	0	0	5,943	118	316	6,377	56%
2013	6,063	0	0	6,063	120	322	6,505	56%
2014	5,784	0	0	5,784	122	294	6,200	56%
2015	5,902	0	0	5,902	124	300	6,325	56%
2016	6,018	0	0	6,018	0	306	6,324	55%
2017	6,132	0	0	6,132	0	311	6,444	55%
2018	6,246	0	0	6,246	0	317	6,563	55%
2019	6,362	0	0	6,362	0	323	6,686	55%
2020	6,482	0	0	6,482	0	329	6,811	55%

[1] Amounts shown for 2001 through 2010 represent historical values. Amounts shown for 2011 through 2020 represent forecast values.

[2] Represents the Retail Load of the ARP Participants.

[3] Includes wholesale sales in 2011 through 2015 to the City of Quincy.

[4] Includes both ARP and Quincy loads and losses.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Net Firm Demand
2011	1,351	1,325	26	0	0	0	0	0	0	1,351
2012	1,375	1,349	26	0	0	0	0	0	0	1,375
2013	1,403	1,376	27	0	0	0	0	0	0	1,403
2014	1,341	1,314	27	0	0	0	0	0	0	1,341
2015	1,369	1,341	28	0	0	0	0	0	0	1,369
2016	1,368	1,368	0	0	0	0	0	0	0	1,368
2017	1,395	1,395	0	0	0	0	0	0	0	1,395
2018	1,421	1,421	0	0	0	0	0	0	0	1,421
2019	1,448	1,448	0	0	0	0	0	0	0	1,448
2020	1,475	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)
		Wholesale								
Year	Total	ARP	Quincy	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
2010/11	1,278	1,254	24	0	0	0	0	0	0	1,278
2011/12	1,301	1,276	25	0	0	0	0	0	0	1,301
2012/13	1,327	1,302	25	0	0	0	0	0	0	1,327
2013/14	1,283	1,257	26	0	0	0	0	0	0	1,283
2014/15	1,309	1,283	26	0	0	0	0	0	0	1,309
2015/16	1,283	1,283	0	0	0	0	0	0	0	1,283
2016/17	1,307	1,307	0	0	0	0	0	0	0	1,307
2017/18	1,332	1,332	0	0	0	0	0	0	0	1,332
2018/19	1,357	1,357	0	0	0	0	0	0	0	1,357
2019/20	1,383	1,383	0	0	0	0	0	0	0	1,383

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	ARP Retail [2]	Wholesale [3]	Utility Use & Losses	Net Energy for Load [4]	Load Factor %
2011	6,074	0	0	6,074	116	320	6,509	55%
2012	6,183	0	0	6,183	118	325	6,625	56%
2013	6,307	0	0	6,307	120	331	6,759	56%
2014	6,019	0	0	6,019	122	302	6,443	56%
2015	6,142	0	0	6,142	124	308	6,574	56%
2016	6,263	0	0	6,263	0	314	6,577	55%
2017	6,381	0	0	6,381	0	320	6,702	55%
2018	6,500	0	0	6,500	0	326	6,826	55%
2019	6,621	0	0	6,621	0	332	6,953	55%
2020	6,744	0	0	6,744	0	338	7,083	55%

[1] Values represent predicted net energy for load under severe weather conditions.
[2] Represents the Retail Load of the ARP Participants.
[3] Years 2011 through 2015 include the expected NEL of the City of Quincy, after other Quincy resources have been utilized.
[4] Includes both ARP and Quincy loads and losses.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	Net Firm
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2011	1,260	1,234	25	0	0	0	0	0	0	1,260
2012	1,282	1,256	26	0	0	0	0	0	0	1,282
2013	1,308	1,282	26	0	0	0	0	0	0	1,308
2014	1,250	1,223	27	0	0	0	0	0	0	1,250
2015	1,275	1,248	27	0	0	0	0	0	0	1,275
2016	1,273	1,273	0	0	0	0	0	0	0	1,273
2017	1,298	1,298	0	0	0	0	0	0	0	1,298
2018	1,323	1,323	0	0	0	0	0	0	0	1,323
2019	1,348	1,348	0	0	0	0	0	0	0	1,348
2020	1,373	1,373	0	0	0	0	0	0	0	1,373

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

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Wholesale				Residential Load		Commercial/ Industrial Load	Commercial/ Industrial Load	Net Firm
Year	Total	ARP	Quincy	Retail	Interruptible	Management	Residential Conservation	Management	Conservation	Demand
2010/11	1,258	1258 [2]	0	0	0	0	0	0	0	1,258
2011/12	1,188	1,163	25	0	0	0	0	0	0	1,188
2012/13	1,211	1,186	25	0	0	0	0	0	0	1,211
2013/14	1,169	1,144	26	0	0	0	0	0	0	1,169
2014/15	1,194	1,168	26	0	0	0	0	0	0	1,194
2015/16	1,191	1,191	0	0	0	0	0	0	0	1,191
2016/17	1,214	1,214	0	0	0	0	0	0	0	1,214
2017/18	1,237	1,237	0	0	0	0	0	0	0	1,237
2018/19	1,261	1,261	0	0	0	0	0	0	0	1,261
2019/20	1,284	1,284	0	0	0	0	0	0	0	1,284

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

[2] Actual 2010/11 Winter Peak occurred in December 2010, before the Quincy Sale began.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	ARP Retail [2]	Wholesale [3]	Utility Use & Losses	Net Energy for Load [4]	Load Factor %
2011	5,653	0	0	5,653	116	305	6,074	56%
2012	5,754	0	0	5,754	118	310	6,182	56%
2013	5,870	0	0	5,870	120	316	6,306	56%
2014	5,598	0	0	5,598	122	289	6,009	56%
2015	5,713	0	0	5,713	124	294	6,131	56%
2016	5,825	0	0	5,825	0	300	6,125	55%
2017	5,935	0	0	5,935	0	306	6,241	55%
2018	6,046	0	0	6,046	0	311	6,357	55%
2019	6,158	0	0	6,158	0	317	6,476	55%
2020	6,274	0	0	6,274	0	323	6,597	55%

[1] Values represent predicted net energy for load under mild weather conditions.
[2] Represents the Retail Load of the ARP Participants.
[3] Years 2011 through 2015 show the expected NEL of the City of Quincy to be served by the ARP.
[4] Includes both ARP and Quincy loads and losses

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 - 2010		Forecast - 2011 [1]		Forecast - 2012 [1]	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,412	536	1,205	493	1,226	502
February	1,054	446	1,059	439	1,078	447
March	1,000	426	922	445	938	452
April	840	424	970	466	988	475
May	1,087	563	1,133	557	1,153	566
June	1,272	624	1,243	604	1,265	613
July	1,255	646	1,261	617	1,284	629
August	1,263	638	1,300	656	1,323	667
September	1,171	582	1,190	581	1,211	591
October	1,049	482	1,075	512	1,094	522
November	844	408	922	430	940	438
December	1,258	525	910	466	928	475

[1] Years 2011 and 2012 show expected ARP requirements including the sale to the City of Quincy.

Florida Municipal Power Agency

Section 4.0

Renewable Resources and Conservation Programs

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Section 4 Renewable Resources and Conservation Programs

4.1 Introduction

FMPA continually evaluates renewable and conservation 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 operates a Conservation & Energy Efficiency Program and a Net Metering Program.

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 (DC) 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 2010, FMPA purchased 15,800 MWh of energy from this renewable resource.

In addition, the ARP receives energy from the ARP's and ARP Participants' shares (21.42% in the aggregate as of December 31, 2010) in the Stanton Energy Center Units 1 and 2 which burns landfill gas as a supplemental fuel source. In 2010 the Stanton Energy Center consumed 495,764 MMbtu of landfill gas, of which 106,193 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 Conservation & Energy Efficiency Program

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 in 2008, the ARP Participants have allocated more than $2.25 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.

4.4 Net Metering Program

In June 2008, the ARP Participants adopted a Net Metering Policy to permit interconnection of customer-owned renewable generation to its Members' 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 2010, ARP had approximately 522 kW of solar photovoltaic renewable generation connected to the grid through the Net Metering Program.

As with the conservation 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.

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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 completing the construction of a nominal 300 MW (summer rating), natural gas-fired combined cycle unit at the Cane Island Power Park. Cane Island Unit 4 (CI4) is currently scheduled for commercial operation in May 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 FPL and Southern Company. Power purchase contracts included in the ARP plans are briefly summarized below:

-

- **FPL:** FMPA has a long-term purchase contract with FPL for 45 MW until June 2013. The FPL long-term purchase is a Partial Requirements type purchase and includes reserves.

- **Southern Company:** The ARP and KUA each have a contract for the purchase of power on a percentage of net operating capability from Southern Power's Stanton A combined cycle plant that extends to 2023 and has various extension options. For 2011, the ARP's and KUA's combined purchases amount to 79 MW. FMPA also has a contract for approximately 162 MW (Summer rating) or 180 (Winter rating) of peaking capacity from Southern Power's Oleander Unit 5 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 2020 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) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
	Crystal River 3	26	26	29	29	29	29	29	29	29	29
	St. Lucie 2	49	55	55	34	34	34	34	34	34	34
1	Excluded Resources (Nuclear)	74	80	84	64	64	64	64	64	64	64
2	Stanton Coal Plant	185	185	185	175	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	383	383	383	383	383	383	383	383	383	383
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	43	43	43	43	-	-	-	-	-	-
11	Lake Worth Native Generation	88	88	88	-	-	-	-	-	-	-
12	Sub Total Existing Resources	1,304	1,310	1,314	1,195	1,152	1,152	1,152	1,152	1,152	1,152
	Planned Additions										
13	Cane Island 4	301	301	301	301	301	301	301	301	301	301
15	Sub Total Planned Additions	301	301	301	301	301	301	301	301	301	301
16	**Total Installed Capacity**	**1,605**	**1,611**	**1,615**	**1,496**	**1,453**	**1,453**	**1,453**	**1,453**	**1,453**	**1,453**
	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	162	162	162	162	162	162	162	162	162	162
19	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	12
20	Sub Total Without Reserves	241	241	241	241	241	241	241	241	241	253
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	-	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	45	-	-	-	-	-	-	-	-
23	Sub Total With Reserves	45	45	-	-	-	-	-	-	-	-
24	**Total Firm Capacity Import**	**286**	**286**	**241**	**241**	**241**	**241**	**241**	**241**	**241**	**253**
25	**Total Available Capacity**	**1,891**	**1,897**	**1,856**	**1,737**	**1,694**	**1,694**	**1,694**	**1,694**	**1,694**	**1,706**

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

Line No.	Resource Description	Winter Rating (MW) [1]									
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	76	82	86	65	65	65	65	65	65	65
2	Stanton Coal Plant	186	186	186	175	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	398	398	398	398	398	398	398	398	398	398
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	-	-	-	-	-	-
11	Lake Worth Native Generation	92	92	92	-	-	-	-	-	-	-
12	Sub Total Existing Resources	1,359	1,365	1,369	1,246	1,201	1,201	1,201	1,201	1,201	1,201
	Planned Additions										
13	Cane Island 4	-	310	310	310	310	310	310	310	310	310
15	Sub Total Planned Additions	-	310	310	310	310	310	310	310	310	310
16	**Total Installed Capacity**	**1,359**	**1,675**	**1,679**	**1,556**	**1,511**	**1,511**	**1,511**	**1,511**	**1,511**	**1,511**
	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	180	180	180	180	180	180	180	180	180	180
19	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
20	Sub Total Without Reserves	259	259	259	259	259	259	259	259	259	259
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	-	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	45	45	-	-	-	-	-	-	-
23	Sub Total With Reserves	45	45	45	-	-	-	-	-	-	-
24	**Total Firm Capacity Import**	**304**	**304**	**304**	**259**	**259**	**259**	**259**	**259**	**259**	**259**
26	**Total Available Capacity**	**1,663**	**1,979**	**1,983**	**1,815**	**1,770**	**1,770**	**1,770**	**1,770**	**1,770**	**1,770**

[1] The 2011 Winter Season in this document is considered December 2010 through February 2011

Schedule 5
Fuel Requirements – All-Requirements Power Supply Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Unit	Fuel	Actual	Forecasted									
No.	Fuel Type	Type	Units	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Nuclear [1]		Trillion BTU	6	6	7	7	6	5	6	5	6	5	6
2	Coal		000 Ton	459	443	442	464	449	452	451	440	410	392	409
	Residual													
3		Steam	000 BBL	-	1	2	2	2	2	1	1	1	2	2
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	1	2	2	2	2	1	1	1	2	2
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	21	43	47	58	63	70	74	79	87	94	102
10		Total	000 BBL	21	43	47	58	63	70	74	79	87	94	102
	Natural Gas													
11		Steam	000 MCF	79	1	-	4	-	-	-	-	-	-	-
12		CC	000 MCF	26,302	23,366	25,838	27,240	26,540	27,960	28,575	30,074	31,433	34,247	32,757
13		CT	000 MCF	550	50	18	57	72	97	56	123	135	149	149
14		Total	000 MCF	26,931	23,417	25,856	27,301	26,612	28,056	28,631	30,197	31,568	34,395	32,906
	Renewables [2]													
15		Biofuels	Billion BTU	158	158	158	158	158	158	158	158	158	158	158
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hyrdro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	128	203	189	174	155	146	137	128	119	110	102
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	286	361	347	332	313	304	295	286	277	268	260
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-

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

Schedule 6.1
Energy Sources (GWh) – All-Requirements 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	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Annual Firm Inter-													
1	Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	538	585	626	627	525	497	510	495	524	481	526
3	Coal		GWh	1,181	1,140	1,136	1,200	1,165	1,172	1,170	1,138	1,051	999	1,048
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	10	20	22	28	30	34	36	38	42	45	50
11		Total	GWh	10	20	22	28	30	34	36	38	42	45	50
	Natural Gas													
12		Steam	GWh	4	0	-	0	-	-	-	-	-	-	-
13		CC	GWh	3,607	3,235	3,610	3,776	3,613	3,801	3,899	4,087	4,304	4,638	4,515
14		CT	GWh	37	3	1	4	5	7	4	8	9	10	10
15		Total	GWh	3,648	3,238	3,611	3,781	3,618	3,808	3,903	4,095	4,313	4,648	4,525
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [2]													
17		Biofuels	GWh	16	16	16	16	16	16	16	16	16	16	16
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	13	21	20	18	16	15	14	13	12	11	11
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	28	37	35	34	32	31	30	29	28	27	26
27	Interchange		GWh	893	1,388	1,163	1,101	1,125	1,124	1,056	1,070	1,063	978	1,165
28	Net Energy for Load [3]		GWh	6,299	6,409	6,593	6,771	6,495	6,665	6,705	6,866	7,021	7,180	7,341

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

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

[3] Includes transmission losses.

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

Line No. (1)	Energy Source	(2) Prime Mover	(3) Units	(4) Actual 2010	(5) Forecasted 2011	(6) 2012	(7) 2013	(8) 2014	(9) 2015	(10) 2016	(11) 2017	(12) 2018	(13) 2019	(14) 2020
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	8.5	9.1	9.5	9.3	8.1	7.5	7.6	7.2	7.5	6.7	7.2
3	Coal		%	18.8	17.8	17.2	17.7	17.9	17.6	17.4	16.6	15.0	13.9	14.3
	Residual													
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.2	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7
11		Total	%	0.2	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7
	Natural Gas													
12		Steam	%	0.1	0.0	-	0.0	-	-	-	-	-	-	-
13		CC	%	57.3	50.5	54.7	55.8	55.6	57.0	58.2	59.5	61.3	64.6	61.5
14		CT	%	0.6	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
15		Total	%	57.9	50.5	54.8	55.8	55.7	57.1	58.2	59.6	61.4	64.7	61.6
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
	Renewables [2]													
17		Biofuels	%	0.3	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	%	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.1
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		%	14.2	21.7	17.6	16.3	17.3	16.9	15.8	15.6	15.1	13.6	15.9
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 Project participants.

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	Total System Firm Summer Peak Demand (MW) [2][3]			Reserve Margin before Maintenance [4]		Scheduled Maintenance	Reserve Margin after Maintenance [4]	
Year	(MW) [1]	(MW)	(MW) [2]	QF (MW)	(MW)	Peak	Losses	Total	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2011	1,605	286	0	0	1,891	1,300	24	1,324	567	44%	0	567	44%
2012	1,611	286	0	0	1,897	1,325	24	1,349	548	42%	0	548	42%
2013	1,615	241	0	0	1,856	1,350	25	1,375	481	35%	0	481	35%
2014	1,496	241	0	0	1,737	1,291	23	1,314	423	32%	0	423	32%
2015	1,453	241	0	0	1,694	1,317	24	1,341	353	26%	0	353	26%
2016	1,453	241	0	0	1,694	1,315	24	1,339	355	27%	0	355	27%
2017	1,453	241	0	0	1,694	1,340	25	1,365	329	24%	0	329	24%
2018	1,453	241	0	0	1,694	1,366	25	1,391	303	22%	0	303	22%
2019	1,453	241	0	0	1,694	1,392	25	1,417	277	20%	0	277	20%
2020	1,453	253	0	0	1,706	1,418	26	1,444	262	18%	0	262	18%

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

[2] The Quincy Sale is represented as part of the System Firm Peak Demand.

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

[4] 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)	(6)		(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW) [1]	Firm Capacity Export (MW) [2]	QF (MW)	Total Available Capacity (MW)	System Firm Winter Peak Demand (MW) [2][3]			Reserve Margin before Maintenance [4]		Scheduled Maintenance (MW)	Reserve Margin after Maintenance [4]	
						Peak	Losses	Total	(MW)	(% of Peak)		(MW)	(% of Peak)
2010/11	1,359	304	0	0	1,663	1,258	23	1,228	435	37%	0	435	37%
2011/12	1,675	304	0	0	1,979	1,226	23	1,249	730	61%	0	730	61%
2012/13	1,679	304	0	0	1,983	1,251	24	1,274	709	58%	0	709	58%
2013/14	1,556	259	0	0	1,815	1,208	22	1,230	585	48%	0	585	48%
2014/15	1,511	259	0	0	1,770	1,233	23	1,256	514	41%	0	514	41%
2015/16	1,511	259	0	0	1,770	1,231	23	1,254	516	41%	0	516	41%
2016/17	1,511	259	0	0	1,770	1,255	23	1,278	491	38%	0	491	38%
2017/18	1,511	259	0	0	1,770	1,279	24	1,302	467	36%	0	467	36%
2018/19	1,511	259	0	0	1,770	1,303	24	1,327	443	33%	0	443	33%
2019/20	1,511	259	0	0	1,770	1,327	25	1,352	418	31%	0	418	31%

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

[2] The Quincy Sale is represented as part of the System Firm Peak Demand.

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

[4] 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		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability		Status
				Primary	Alt.	Primary	Alt.					Summer MW	Winter MW	
Resource Additions														
Cane Island	CC4	Osceola	CC	NG	-	PL	-	NA	05/11	NA	NA	301	310	V
Changes to Existing Resources														
Crystal River	3	Citrus	NP	UR	-	TK	-	NA	05/11	NA	NA	1	1	A
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	10/12	NA	NA	6	6	A
Crystal River	3	Citrus	NP	UR	-	TK	-	NA	05/13	NA	NA	7	7	A
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	NA	01/14	NA	NA	(10)	(10)	OT [1]
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	01/14	NA	NA	(21)	(21)	OT [1]
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	NA	01/14	NA	NA	(26)	(27)	OT [1]
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	NA	01/14	NA	NA	(20)	(21)	OT [1]
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [1]
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [1]
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [1]
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [1]
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	NA	01/14	NA	NA	(2)	(2)	OT [1]
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	NA	01/14	NA	NA	(24)	(25)	OT [1]
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	NA	01/14	NA	NA	(8)	(9)	OT [1]
Hansel Plant	21	Osceola	CT	NG	-	PL	-	NA	02/83	09/14	38	(28)	(34)	RT
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	09/14	8	(8)	(5)	RT
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	09/14	8	(8)	(5)	RT

[1] 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

Community Power + Statewide Strength ®

Section 6 Site and Facility Descriptions

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

- 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 existing generation sites located within or adjacent to the service territories of ARP Participants, such as the Stock Island site at KEYS, the Cane Island Power Park site at KUA, or the Treasure Coast Energy Center in Fort Pierce. FMPA also 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 Participants' service territories 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: Units 1-3 include 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 completing construction of CI4, a nominal 300 MW (summer rating), natural gas-fired 1x1 GE 7FA combined cycle unit wholly owned by the ARP. CI4 is currently scheduled for commercial operation in May 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. 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.

General

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

Note: FMPA currently has no new proposed transmission lines.

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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 facility additions for ARP Participant cities.

Table II-1
Planned and Proposed Transmission Additions for ARP Participants
2011 through 2020 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
FMPA/KEYS	STATCOM/Shunt Capacitor at Big Pine Key Substation			138 kV		6/2012
	STATCOM /Shunt Capacitor at Stock Island Substation			138 kV		6/2012
Ft. Pierce	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	1	9/2019
	Southwest Sub Auto-Xfmr Addition		20	138/13.2 kV	2	9/2019
	Southwest Substation			138/13.2 kV		9/2019
Kissimmee	Clay Auto-Txfmr		224	230/69 kV	2	5/2011
	Clay Street (Reconductor)	Airport		69 kV	1	6/2011
	Osceola Parkway Substation			69 kV		6/2017
	Lake Bryan	Osceola Parkway		69 kV	1	6/2017
	Lake Cecile	Osceola Parkway		69 kV	1	6/2017
	Domingo Toro Substation			69 kV		6/2019
Ocala	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)
2011	1,891	1,324	45	567	44%
2012	1,897	1,349	45	548	42%
2013	1,856	1,375	0	481	35%
2014	1,737	1,314	0	423	32%
2015	1,694	1,341	0	353	26%
2016	1,694	1,339	0	355	27%
2017	1,694	1,365	0	329	24%
2018	1,694	1,391	0	303	22%
2019	1,694	1,417	0	277	20%
2020	1,706	1,444	0	262	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)
2010/11	1,663	1,228	45	435	37%
2011/12	1,979	1,249	45	730	61%
2012/13	1,983	1,274	45	709	58%
2013/14	1,815	1,230	0	585	48%
2014/15	1,770	1,256	0	514	41%
2015/16	1,770	1,254	0	516	41%
2016/17	1,770	1,278	0	491	38%
2017/18	1,770	1,302	0	467	36%
2018/19	1,770	1,327	0	443	33%
2019/20	1,770	1,352	0	418	31%

[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)