



Florida Municipal Power Agency

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

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

120000-07

RECEIVED-FPSC  
12 MAR 30 AM 9:56  
COMMISSION  
CLERK

**Re: FMPA's 2012 Ten Year Site Plan**

March 29, 2012

Dear Sir/Madam:

Pursuant to Rule 25-22.071(1) Florida Administrative Code, FMPA is hereby submitting 25 copies of its 2012 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

Enc.

cc. File

12 MAR 30 AM 11 52

DOCUMENT NUMBER - DATE  
01875 MAR 30 12  
FPSC-COMMISSION CLERK

COM \_\_\_\_\_  
APA \_\_\_\_\_  
ECR \_\_\_\_\_  
GCL 2 \_\_\_\_\_  
RAD 22 \_\_\_\_\_  
SRC \_\_\_\_\_  
ADM \_\_\_\_\_  
OPC \_\_\_\_\_  
CLK [original]



Florida Municipal Power Agency

# Ten-Year Site Plan

April 2012

Community Power + Statewide Strength®

DOCUMENT NUMBER-DATE

01875 MAR 30 2012

FPSC-COMMISSION CLERK



Florida Municipal Power Agency

# Ten-Year Site Plan 2012-2021

Submitted to

Florida Public Service Commission

April 1, 2012

Community Power + Statewide Strength ®



Florida Municipal Power Agency

# Table of Contents

Community Power + Statewide Strength®

## Table of Contents

Executive Summary.....	ES-1
Section 1 Description of FMPA .....	1-1
1.1 FMPA .....	1-1
1.2 All-Requirements Power Supply Project.....	1-2
1.3 Other FMPA Power Supply Projects.....	1-7
1.4 Summary of Projects .....	1-9
Section 2 Description of Existing Facilities .....	2-1
2.1 ARP Supply-Side Resources .....	2-1
2.2 ARP Transmission System .....	2-2
2.2.1 ARP Participant Transmission Systems.....	2-3
2.2.2 ARP Transmission Agreements.....	2-6
Section 3 Forecast of Demand and Energy for the All-Requirements Power Supply Project.....	3-1
3.1 Introduction .....	3-1
3.2 Load Forecast Process .....	3-1
3.3 2012 Load Forecast Overview.....	3-2
3.4 Methodology.....	3-2
3.4.1 Model Specifications .....	3-3
3.4.2 Projection of NEL and Peak Demand.....	3-4
3.5 Data Sources.....	3-5
3.5.1 Historical ARP Participant Retail Sales Data .....	3-5
3.5.2 Weather Data .....	3-5
3.5.3 Economic Data.....	3-5
3.5.4 Real Electricity Price Data.....	3-6
3.6 Overview of Results .....	3-6
3.6.1 Base Case Forecast .....	3-6
3.6.2 Weather-Related Uncertainty of the Forecast.....	3-6
3.7 Load Forecast Schedules .....	3-7
Section 4 Renewable Resources and Conservation Programs.....	4-1
4.1 Introduction .....	4-1
4.2 Renewable Resources.....	4-1
4.2.1 Solar Photovoltaic.....	4-1
4.2.2 Biomass.....	4-1
4.2.3 Plasma Arc.....	4-2
4.3 Conservation & Energy Efficiency Program.....	4-2
4.4 Net Metering Program .....	4-3
4.5 Load Management Program .....	4-4
Section 5 Forecast of Facilities Requirements .....	5-1
5.1 ARP Planning Process.....	5-1
5.2 Planned ARP Generating Facility Requirements .....	5-1

5.3 Capacity and Power Purchase Requirements ..... 5-1  
 5.4 Summary of Current and Future ARP Resource Capacity ..... 5-2  
 Section 6 Site and Facility Descriptions..... 6-1

**List of Figures, Tables and Required Schedules**

Table ES-1 FMPA ARP Summer 2011 Capacity Resources ..... ES-2  
 Figure ES-1 ARP Participants and FMPA Power Supply Resource Locations..... ES-3  
 Figure 1-1 ARP Participant Cities..... 1-3  
 Table 1-1 St. Lucie Project Participants..... 1-7  
 Table 1-2 Stanton Project Participants..... 1-8  
 Table 1-3 Tri-City Project Participants ..... 1-8  
 Table 1-4 Stanton II Project Participants ..... 1-8  
 Table 1-5 Summary of FMPA Power Supply Project Participants..... 1-9  
 Table 2-1 ARP Supply-Side Resources Summer 2011 ..... 2-1  
 Schedule 1 Existing Generating Facilities as of December 31, 2010..... 2-7  
 Figure 3-1 Load Forecast Process ..... 3-1  
 Schedule 2.1 History and Forecast of Energy Consumption and Number of Customers by Customer Class..... 3-9  
 Schedule 2.2 History and Forecast of Energy Consumption and Number of Customers by Customer Class..... 3-10  
 Schedule 2.3 History and Forecast of Energy Consumption and Number of Customers by Customer Class..... 3-11  
 Schedule 3.1 History and Forecast of Summer Peak Demand (MW) – Base Case ..... 3-12  
 Schedule 3.2 History and Forecast of Winter Peak Demand (MW) – Base Case..... 3-13  
 Schedule 3.3 History and Forecast of Annual Net Energy for Load (GWh) – Base Case..... 3-14  
 Schedule 3.1a Forecast of Summer Peak Demand (MW) – High Case..... 3-15  
 Schedule 3.2a Forecast of Winter Peak Demand (MW) – High Case ..... 3-16  
 Schedule 3.3a Forecast of Annual Net Energy for Load (GWh) – High Case ..... 3-17  
 Schedule 3.1b Forecast of Summer Peak Demand (MW) – Low Case..... 3-18  
 Schedule 3.2b Forecast of Winter Peak Demand (MW) – Low Case..... 3-19  
 Schedule 3.3b Forecast of Annual Net Energy for Load (GWh) – Low Case ..... 3-20  
 Schedule 4 Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month ..... 3-21  
 Table 5-1 Summary of All-Requirements Power Supply Project Resource Summer Capacity ..... 5-3  
 Table 5-2 Summary of All-Requirements Power Supply Project Resource Winter Capacity..... 5-4  
 Schedule 5 Fuel Requirements – All-Requirements Power Supply Project ..... 5-5  
 Schedule 6.1 Energy Sources (GWh) – All-Requirements Power Supply Project ..... 5-6  
 Schedule 6.2 Energy Sources (%) – All-Requirements Power Supply Project..... 5-7

Schedule 7.1 Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak..... 5-8

Schedule 7.2 Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak ..... 5-9

Schedule 8 Planned and Prospective Generating Facility Additions and Changes..... 5-10

Schedule 9 Status Report and Specifications of Proposed Generating Facilities..... 6-3

Schedule 10 Status Report and Specifications of Proposed Directly Associated Transmission Lines..... 6-4

**Appendices**

Appendix I List of Abbreviations ..... I-1

Appendix II ARP Participant Transmission Information.....II-1

Appendix III Additional Reserve Margin Information ..... III-1



Florida Municipal Power Agency

# Executive Summary

Community Power + Statewide Strength®



## Executive Summary

The following information is provided in accordance with Florida Public Service Commission (PSC) Rules 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan (TYSP). The TYSP 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 2012 is 1,894 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 2012 Capacity Resources**

<b>Resource Category</b>	<b>Summer Capacity (MW)</b>
Nuclear	77
ARP Ownership	1,126
ARP Participant Ownership	405
Power Purchases	286
<b>Net Total 2012 ARP Resources</b>	<b>1,894</b>

Based on the ARP’s 2012 Load Forecast, the ARP is expected to be able to meet its generation capacity requirements with existing resources through 2021. The projected peak native ARP summer load for 2012 is 1,265 MW and is forecast to increase to 1,392 MW in 2021. At this time, FMPA is planning to meet the ARP’s need for additional generation capacity in 2022 through a power purchase, or unit participation agreement 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.

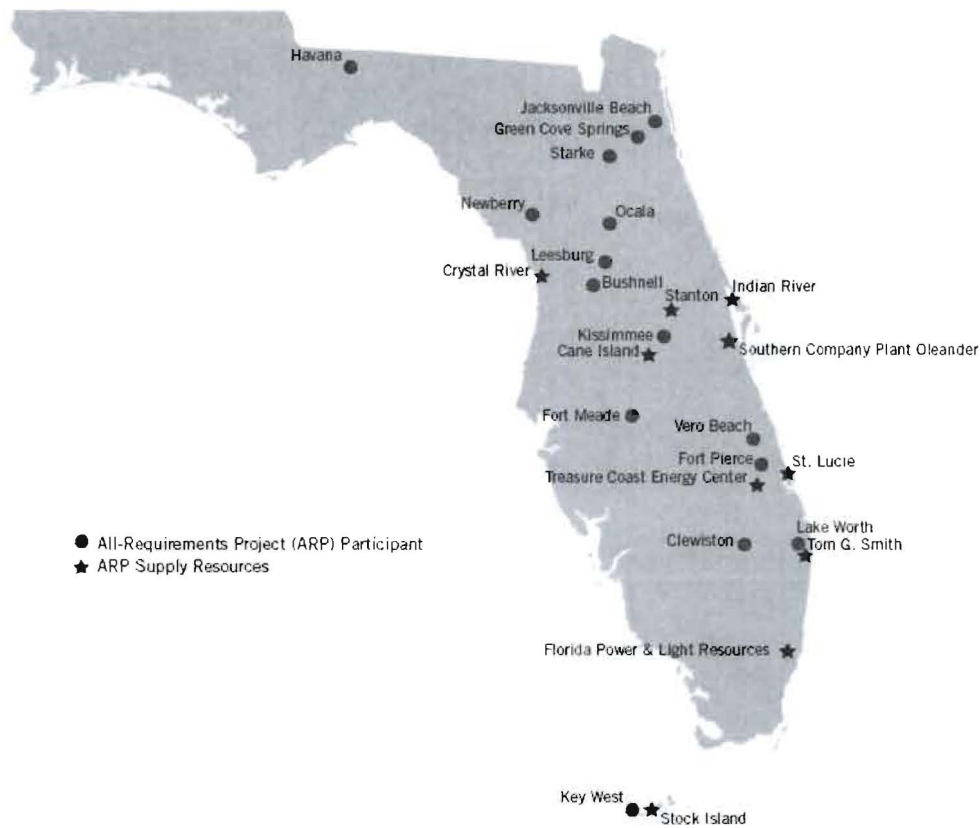
In 2010, FMPA, on behalf of the ARP, responded to a Request for Proposals from the City of Quincy for providing full-requirements capacity and energy beyond Quincy’s entitlement in a Southeastern Power Administration (SEPA) Project. The ARP was awarded the Quincy contract for the term of January 1, 2011 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 2012. The sale to Quincy increases the projected ARP load to 1,291 MW for the summer of 2012.

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 independently piloting Demand Side Management programs aimed at reducing their loads during peak energy usage periods.

A location map of the ARP Participants and FMPA’s power resources as of December 31, 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

Community Power + Statewide Strength ®

## 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)<sup>1</sup>. 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 Utility Board of City of Key West, Florida (KEYS)
- 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.

---

<sup>1</sup> 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 Hickie 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](http://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](http://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](http://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 Thies 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.fpu.com](http://www.fpu.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](http://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](http://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](http://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 Tejada 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](http://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](http://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](http://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](http://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. Bill Conrad is the Mayor and 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](http://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](http://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](http://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 Pilar Turner is the Mayor. The City's service area is approximately 41 square miles. For more information about the City of Vero Beach, please visit [www.covb.org](http://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 located in St. Lucie County. 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 December 31, 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

Community Power + Statewide Strength ®

## 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 2012 summer season are shown by ownership capacity in Table 2-1.

**Table 2-1  
ARP Supply-Side Resources Summer 2012**

Resource Category	Summer Capacity (MW)
1) Nuclear	77
2) ARP Ownership	
Existing	1,126
New	-
Sub Total ARP Ownership	1,126
3) Participant Ownership	
KEYS	31
KUA	285
Lake Worth	88
Sub Total Participant Ownership	405
4) Power Purchases	286
Total 2012 ARP Resources	1,894

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 Power Supply 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 Power Supply 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 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 December 31, 2011 includes capacity and energy purchased from FPL and Southern Company.

Information regarding existing ARP generation resources as of December 31, 2011, 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 six 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. KEYS/FMPA is in the process of installing STATCOMS and shunt capacitors at Big Pine and Stock Island Substations planned to be in operation by the summer of 2012. In addition, a series capacitor at Islamorada is being planned with Florida Keys Electric Coop (FKEC) to be in operation by the summer of 2013. These projects will enable the Florida Keys (KEYS/FMPA and FKEC) to increase the import limit of the 138 kV transmission line to be equal to its thermal limit.

### **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 48.8 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, 71.19 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, 2011**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transportation		Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max Nameplate MW	Net Capability	
				Primary	Alternate	Primary	Alternate				Summer (MW)	Winter (MW)
<b>Nuclear Capacity</b>												
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	51	52
Total Nuclear Capacity											77	78
<b>ARP Owned Generation</b>												
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	19
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
Cane Island	4	Osceola	CC	NG	DFO	PL	TK	08/11	NA	315	300	310
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											1,126	1,173
<b>Participant Owned Generation</b>												
<b>Kissimmee Utility Authority</b>												
Hansel Plant	21	Osceola	CT	NG	-	PL	-	02/83	09/12	38	28	34
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	09/12	8	8	5
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	09/12	8	8	5
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	19
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, 2011**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12) (13)	
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transportation		Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max Nameplate MW	Net Capability	
				Primary	Alternate	Primary	Alternate				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	300
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	423
Total Generation Resources											1,608	1,674



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

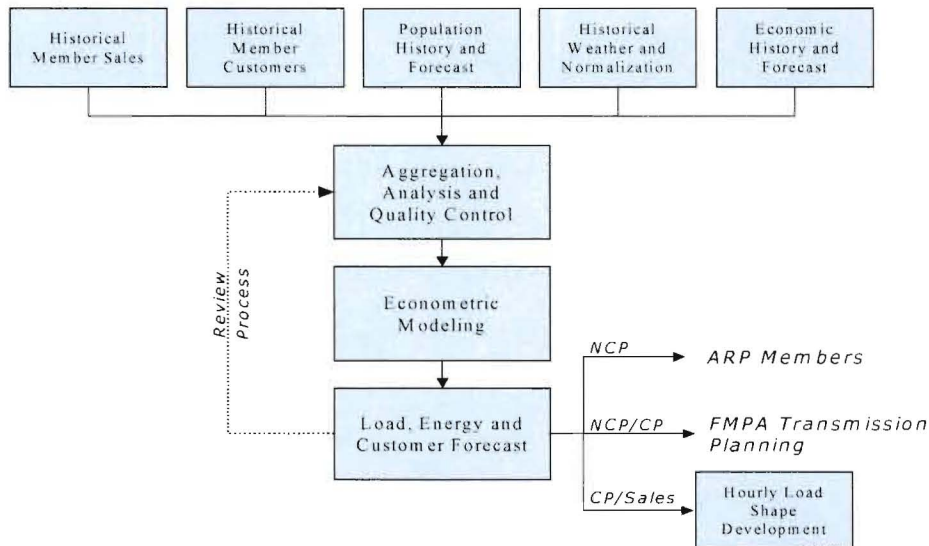
### 3.1 Introduction

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 2012 Load Forecast Overview**

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2012 through 2031. 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 1999-2011.

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 (2007-2011). 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 2011 (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 (NEL) to be supplied to ARP Participants is expected to grow at an annual average growth rate of 1.0% from 2012-2021, and at 1.6% from Fiscal Year 2022-2031. The Base Case 2012 ARP forecast summer peak demand is 1,265 MW and forecast annual NEL for Calendar Year 2012 is 6,116 GWh. (These values do not include the Quincy Sale.)

FMPA's ARP has entered into a five year contract with the City of Quincy (Quincy) to provide all of its bulk power requirements which are above and beyond purchases from Southeastern Power Administration (SEPA). Quincy's load forecast was developed by FMPA staff and was based on Quincy monthly historical peaks and energy for 2008 through 2009. Monthly distribution ratios were developed and then projected forward taking into account Quincy's SEPA contract and escalated at 1.2% annually. Quincy's 2012 forecast summer peak demand requirement from the ARP is 26 MW and forecast annual NEL for Calendar Year 2012 is 115 GWh.

The combination of Quincy's energy requirements from the ARP and the requirements of ARP Participants results in a 2012 forecast summer peak demand of 1,291 MW and a Calendar Year NEL forecast of 6,231 GWh.

### **3.6.2 Weather-Related Uncertainty of the Forecast**

While a forecast that is derived from projections of driving variables that are obtained from reputable sources provides a sound basis for planning, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other

conditions occur that are different from those assumed or provided, the actual ARP Participant load can be expected to vary from the forecast. For various purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

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

The potential weather variability was developed using weather data specific to each weather station generally over the period 1971-2005. These weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, although this is less likely to happen than severe conditions in one season or the other. Accordingly, it should be recognized that annual NEL may be somewhat less volatile than the annual NEL variation shown herein. Conversely, NEL in any particular month may be *more* volatile than shown herein. Finally, because the forecast methodology derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand are effectively assumed to have the same weather-related volatility as annual NEL.

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

### **3.7 Load Forecast Schedules**

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

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 reported demands and energy shown in Schedules 2.1 through 4 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 (as discussed in section 3.6.1) 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)
Year [1]	Rural and Residential [2]				Commercial [2]			
	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
2002	NA	NA	2,426	174,365	13,913	1,996	32,344	61,724
2003	NA	NA	3,178	227,990	13,941	2,603	42,120	61,800
2004	NA	NA	3,172	234,589	13,523	2,625	42,916	61,165
2005	NA	NA	3,269	238,106	13,730	2,675	43,805	61,055
2006	NA	NA	3,293	244,419	13,474	2,692	43,968	61,224
2007	NA	NA	3,273	248,679	13,161	2,740	44,492	61,578
2008	NA	NA	3,127	248,686	12,574	2,767	45,528	60,786
2009	NA	NA	3,169	248,899	12,731	2,669	45,037	59,258
2010	NA	NA	2,951	220,527	13,382	2,271	39,185	57,967
2011	NA	NA	2,887	222,388	12,980	2,261	39,244	57,623
2012	NA	NA	2,833	224,373	12,625	2,263	39,742	56,947
2013	NA	NA	2,888	227,282	12,707	2,297	40,207	57,118
2014	NA	NA	2,721	209,112	13,014	2,168	37,589	57,678
2015	NA	NA	2,779	212,802	13,058	2,206	38,044	57,993
2016	NA	NA	2,834	216,168	13,109	2,245	38,497	58,328
2017	NA	NA	2,887	219,292	13,166	2,284	38,941	58,661
2018	NA	NA	2,941	222,278	13,231	2,324	39,383	59,000
2019	NA	NA	2,996	225,153	13,304	2,364	39,829	59,360
2020	NA	NA	3,051	227,997	13,382	2,405	40,276	59,724
2021	NA	NA	3,106	230,811	13,457	2,446	40,721	60,072

[1] Amounts shown for 2002 through 2011 represent historical values. Amounts shown for 2012 through 2021 represent forecast values.

[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.



**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)
Year [1]	Industrial [2]			and Railways GWh	Highway Lighting GWh	Railroads to Public Authorities GWh	Street & to Ultimate Customers GWh
	GWh	Average No. of Customers	Average kWh Consumption per Customer				
2002	625	1,125	555,920	0	58	122	5,228
2003	615	1,126	546,214	0	69	120	6,586
2004	629	1,134	554,126	0	70	117	6,612
2005	638	1,163	548,974	0	73	115	6,770
2006	660	1,207	546,916	0	76	107	6,829
2007	673	1,221	551,483	0	75	111	6,872
2008	589	991	594,455	0	74	112	6,669
2009	554	960	577,380	0	75	111	6,578
2010	554	997	555,200	0	69	106	5,951
2011	555	1,027	540,239	0	68	103	5,874
2012	567	1,019	556,245	0	69	103	5,834
2013	575	1,028	558,799	0	70	103	5,932
2014	583	1,040	560,562	0	67	104	5,643
2015	592	1,052	562,969	0	68	104	5,750
2016	604	1,067	565,743	0	69	105	5,857
2017	615	1,082	568,367	0	71	106	5,963
2018	627	1,099	570,852	0	72	106	6,070
2019	639	1,115	573,370	0	73	107	6,179
2020	652	1,131	575,986	0	74	108	6,290
2021	664	1,148	578,607	0	75	109	6,400

[1] Amounts shown for 2002 through 2011 represent historical values. Amounts shown for 2012 through 2021 represent forecast values.

[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.

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

(1) Year [1]	(2) Sales for Resale GWh [2]	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
2002	0	305	5,532	0	207,834
2003	0	423	7,008	0	271,236
2004	0	388	7,000	0	278,639
2005	0	374	7,145	0	283,074
2006	0	382	7,211	0	289,594
2007	0	373	7,246	0	294,392
2008	0	296	6,966	0	295,205
2009	0	316	6,894	0	294,896
2010	0	348	6,299	0	260,709
2011	105	229	6,209	0	262,659
2012	115	281	6,231	0	265,134
2013	117	283	6,333	0	268,517
2014	119	259	6,021	0	247,741
2015	121	265	6,135	0	251,898
2016	0	271	6,128	0	255,732
2017	0	273	6,236	0	259,315
2018	0	277	6,347	0	262,759
2019	0	282	6,461	0	266,097
2020	0	290	6,580	0	269,405
2021	0	292	6,692	0	272,679

[1] Amounts shown for 2002 through 2011 represent historical values. Amounts shown for 2012 through 2021 represent forecast values.

[2] Years 2012 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)
Year [1]	Total	Wholesale		Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	ARP Net Firm Demand
		ARP	Quincy							
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	1,280	1,258	22	0	0	0	0	0	0	1,280
2012	1,291	1,265	26	0	0	0	0	0	0	1,291
2013	1,312	1,286	26	0	0	0	0	0	0	1,312
2014	1,251	1,225	27	0	0	0	0	0	0	1,251
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	1,296	1,296	0	0	0	0	0	0	0	1,296
2018	1,319	1,319	0	0	0	0	0	0	0	1,319
2019	1,343	1,343	0	0	0	0	0	0	0	1,343
2020	1,369	1,369	0	0	0	0	0	0	0	1,369
2021	1,392	1,392	0	0	0	0	0	0	0	1,392

[1] Amounts shown for 2002 through 2011 represent historical values. Amounts shown for 2012 through 2021 represent forecast values.

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year [1]	Total	Wholesale		Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	ARP Net Firm Demand
		ARP	Quincy							
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	1,281	1,258	23	0	0	0	0	0	0	1,281
2011/12	1,114	1,096	18	0	0	0	0	0	0	1,114
2012/13	1,238	1,213	25	0	0	0	0	0	0	1,238
2013/14	1,192	1,167	25	0	0	0	0	0	0	1,192
2014/15	1,215	1,189	25	0	0	0	0	0	0	1,215
2015/16	1,235	1,212	22	0	0	0	0	0	0	1,235
2016/17	1,234	1,234	0	0	0	0	0	0	0	1,234
2017/18	1,257	1,257	0	0	0	0	0	0	0	1,257
2018/19	1,280	1,280	0	0	0	0	0	0	0	1,280
2019/20	1,303	1,303	0	0	0	0	0	0	0	1,303
2020/21	1,326	1,326	0	0	0	0	0	0	0	1,326
2021/22	1,349	1,349	0	0	0	0	0	0	0	1,349

[1] Amounts shown for 2002/03 through 2011/12 represent historical values. Amounts shown for 2012/13 through 2021/22 represent forecast values. The Actual Winter 2011/2012 peak occurred in January 2012.

**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 %
2002	5,228	0	0	5,228	0	305	5,532	43%
2003	6,586	0	0	6,586	0	423	7,008	60%
2004	6,612	0	0	6,612	0	388	7,000	56%
2005	6,770	0	0	6,770	0	374	7,145	54%
2006	6,829	0	0	6,829	0	382	7,211	56%
2007	6,872	0	0	6,872	0	373	7,246	54%
2008	6,669	0	0	6,669	0	296	6,966	55%
2009	6,578	0	0	6,578	0	316	6,894	53%
2010	5,951	0	0	5,951	0	348	6,299	56%
2011	5,979	0	0	5,874	105	229	6,209	55%
2012	5,949	0	0	5,834	115	282	6,231	55%
2013	6,049	0	0	5,932	117	284	6,333	55%
2014	5,762	0	0	5,643	119	259	6,021	55%
2015	5,871	0	0	5,750	121	264	6,135	55%
2016	5,857	0	0	5,857	0	271	6,128	55%
2017	5,963	0	0	5,963	0	273	6,236	55%
2018	6,070	0	0	6,070	0	277	6,347	55%
2019	6,179	0	0	6,179	0	282	6,461	55%
2020	6,290	0	0	6,290	0	290	6,580	55%
2021	6,400	0	0	6,400	0	292	6,692	55%

[1] Amounts shown for 2002 through 2011 represent historical values. Amounts shown for 2012 through 2021 represent forecast values.

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

[3] Represents the sales in 2011 through 2015 to the City of Quincy from the ARP.

[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)
Year	Total	Wholesale		Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
		ARP	Quincy							
2012	1,341	1,315	26	0	0	0	0	0	0	1,341
2013	1,363	1,337	26	0	0	0	0	0	0	1,363
2014	1,300	1,273	27	0	0	0	0	0	0	1,300
2015	1,325	1,298	27	0	0	0	0	0	0	1,325
2016	1,324	1,324	0	0	0	0	0	0	0	1,324
2017	1,347	1,347	0	0	0	0	0	0	0	1,347
2018	1,372	1,372	0	0	0	0	0	0	0	1,372
2019	1,397	1,397	0	0	0	0	0	0	0	1,397
2020	1,423	1,423	0	0	0	0	0	0	0	1,423
2021	1,448	1,448	0	0	0	0	0	0	0	1,448

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

**Schedule 3.2a  
Forecast of Winter Peak Demand (MW) – High (Severe Weather) Case  
All-Requirements Power Supply Project <sup>[1]</sup>**

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale		Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/Industrial Load Management	Commercial/Industrial Load Conservation	Net Firm Demand
		ARP	Quincy							
2011/12	1,267	1,242	24	0	0	0	0	0	0	1,267
2012/13	1,287	1,263	25	0	0	0	0	0	0	1,287
2013/14	1,240	1,215	25	0	0	0	0	0	0	1,240
2014/15	1,264	1,239	25	0	0	0	0	0	0	1,264
2015/16	1,263	1,263	0	0	0	0	0	0	0	1,263
2016/17	1,285	1,285	0	0	0	0	0	0	0	1,285
2017/18	1,309	1,309	0	0	0	0	0	0	0	1,309
2018/19	1,333	1,333	0	0	0	0	0	0	0	1,333
2019/20	1,357	1,357	0	0	0	0	0	0	0	1,357
2020/21	1,381	1,381	0	0	0	0	0	0	0	1,381

[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 <sup>[1]</sup>**

(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 %
2012	6,065	0	0	6,065	115	289	6,469	56%
2013	6,168	0	0	6,168	117	290	6,575	56%
2014	5,871	0	0	5,871	119	265	6,255	56%
2015	5,982	0	0	5,982	121	270	6,373	56%
2016	6,094	0	0	6,094	0	278	6,372	55%
2017	6,204	0	0	6,204	0	279	6,483	55%
2018	6,315	0	0	6,315	0	284	6,599	55%
2019	6,429	0	0	6,429	0	289	6,717	55%
2020	6,544	0	0	6,544	0	297	6,841	55%
2021	6,658	0	0	6,658	0	299	6,957	55%

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

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

[3] Years 2012 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 <sup>[1]</sup>**

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale		Retail	Interruptible	Residential	Residential	Commercial/	Commercial/	Net Firm Demand
		ARP	Quincy			Load Management	Conservation	Industrial Load Management	Industrial Load Conservation	
2012	1,252	1,226	26	0	0	0	0	0	0	1,252
2013	1,273	1,246	26	0	0	0	0	0	0	1,273
2014	1,213	1,186	27	0	0	0	0	0	0	1,213
2015	1,236	1,209	27	0	0	0	0	0	0	1,236
2016	1,233	1,233	0	0	0	0	0	0	0	1,233
2017	1,255	1,255	0	0	0	0	0	0	0	1,255
2018	1,278	1,278	0	0	0	0	0	0	0	1,278
2019	1,301	1,301	0	0	0	0	0	0	0	1,301
2020	1,325	1,325	0	0	0	0	0	0	0	1,325
2021	1,348	1,348	0	0	0	0	0	0	0	1,348

[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 <sup>[1]</sup>**

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale		Retail	Interruptible	Residential	Residential	Commercial/	Commercial/	Net Firm Demand
		ARP	Quincy			Load Management	Conservation	Industrial Load Management	Industrial Load Conservation	
2011/12	1,180	1,156	24	0	0	0	0	0	0	1,180
2012/13	1,199	1,175	25	0	0	0	0	0	0	1,199
2013/14	1,154	1,129	25	0	0	0	0	0	0	1,154
2014/15	1,176	1,151	25	0	0	0	0	0	0	1,176
2015/16	1,173	1,173	0	0	0	0	0	0	0	1,173
2016/17	1,194	1,194	0	0	0	0	0	0	0	1,194
2017/18	1,216	1,216	0	0	0	0	0	0	0	1,216
2018/19	1,238	1,238	0	0	0	0	0	0	0	1,238
2019/20	1,261	1,261	0	0	0	0	0	0	0	1,261
2020/21	1,283	1,283	0	0	0	0	0	0	0	1,283

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

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

(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 %
2012	5,651	0	0	5,651	114	278	6,043	56%
2013	5,745	0	0	5,745	115	280	6,140	56%
2014	5,463	0	0	5,463	117	256	5,836	56%
2015	5,566	0	0	5,566	119	260	5,946	56%
2016	5,670	0	0	5,670	0	267	5,937	55%
2017	5,772	0	0	5,772	0	269	6,042	55%
2018	5,876	0	0	5,876	0	274	6,149	55%
2019	5,981	0	0	5,981	0	279	6,260	55%
2020	6,088	0	0	6,088	0	286	6,375	55%
2021	6,195	0	0	6,195	0	288	6,483	55%

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

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

[3] Years 2012 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)	
Month	Actual - 2011 [1]		Forecast - 2012 [2]		Forecast - 2012 [2]		Forecast - 2013 [2]		Forecast - 2013 [2]		Forecast - 2013 [2]	
	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,192	471	1,194	476	1,213	486	1,213	486	1,213	486	1,213	486
February	918	402	1,041	420	1,058	424	1,058	424	1,058	424	1,058	424
March	818	432	880	436	895	444	895	444	895	444	895	444
April	1,086	496	920	458	935	466	935	466	935	466	935	466
May	1,133	547	1,108	536	1,126	544	1,126	544	1,126	544	1,126	544
June	1,261	600	1,213	582	1,233	591	1,233	591	1,233	591	1,233	591
July	1,235	635	1,225	614	1,245	624	1,245	624	1,245	624	1,245	624
August	1,280	655	1,265	635	1,286	645	1,286	645	1,286	645	1,286	645
September	1,142	579	1,156	568	1,175	577	1,175	577	1,175	577	1,175	577
October	1,002	468	1,066	501	1,083	510	1,083	510	1,083	510	1,083	510
November	865	417	885	423	900	429	900	429	900	429	900	429
December	760	426	902	468	917	476	917	476	917	476	917	476

[1] Year 2011 included both the coincidental peak of the ARP and peak supplied to Quincy. 2011 also shows the actual combined NEL for calendar year 2011.

[2] Years 2012 and 2013 show expected ARP requirements including the sale to the City of Quincy.



Florida Municipal Power Agency

# Section 4.0

## Renewable Resources and Conservation Programs

Community Power + Statewide Strength®

## 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 2011, FMPA purchased 21,400 MWh of energy from this renewable resource.
- In 2011, the Stanton Units 1 and 2 consumed 706,842 MMbtu of landfill gas as a supplemental fuel source, of which 157,799 MMbtu is an energy source for the ARP (excluding Vero Beach's share). The ARP receives energy from both the ARP's and

ARP Participants' shares in the Stanton Energy Center Units 1 and 2, which amount to 23.6% of the energy output of Stanton Unit 1 and 19.3% of the energy output of Unit 2 as of December 31, 2011.

These renewable resources help the ARP meet current and future energy needs. However, the existing renewable resources are not considered firm capacity, so they do not assist the ARP in meeting current or future capacity needs.

FMPA has also signed a Letter of Intent with a biomass developer to locate small generating facilities within the service areas of several ARP Participants. This project would allow FMPA to purchase energy from the project under a Power Purchase Agreement. FMPA continues to hold discussions with this vendor as the project develops.

In addition, FMPA continues to hold discussions with other 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 vendor, and is holding discussions on an ongoing basis 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 \$3 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 the program results are still under FMPA's designated threshold for level of significance. FMPA has developed reporting tools and techniques in order to be able to estimate program effects on demand and NEL and understand the level of significance of the program. Once the threshold is crossed, FMPA will separately account for the effects of the energy efficiency program in its demand and load forecast. To the extent that recent energy efficiency efforts have been captured in actual consumption data for the last few 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 2011, the ARP had approximately 705 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 the program results are still under FMPA's designated threshold for level of significance.. 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.

#### **4.5 Load Management Program**

Currently, there are no ARP-wide load management programs in place. However, in 2009, some ARP Participants established load management programs for certain customers, such as those with standby generation for the discreet use by the ARP Participant, not FMPA, or the Balancing Authority. However, FMPA tracks the effects of these load management programs and addresses them accordingly in the load forecast and planning process.



Florida Municipal Power Agency

# Section 5.0

## Forecast of Facilities Requirements

Community Power + Statewide Strength®

## **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**

Based upon FMPA's current Base Load forecast, the ARP currently does not require any additional resources through the term of this study (2021). Schedule 8 at the end of this section shows planned and prospective ARP generating resources 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 1, 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 6.5 percent of the net operating capability of the Stanton A combined cycle facility from Southern Company – Florida LLC. The initial term of the purchase ends in September 2023 and includes subsequent extension options. For 2012, the ARP's and KUA's combined purchases from Stanton A amount to 80.6 MW based on the 620 MW summer rating of the facility. FMPA also has a contract to purchase the entire capacity of, and energy generated by, Southern Power Company's Oleander Unit 5, an approximately 162 MW (summer rating) or 180 MW (winter rating), simple cycle gas turbine unit primarily fueled with natural gas and located in Brevard County. The initial term of the purchase ends in December 2027 and includes a subsequent extension option.

#### **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)									
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	<b>Installed Capacity</b>										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	77	82	35	65	65	65	65	65	65	65
2	Stanton Coal Plant	186	186	177	179	179	179	179	179	179	179
3	Stanton CC Unit A	43	43	43	43	43	43	43	43	43	43
4	Cane Island 1-4	683	683	683	683	683	683	683	683	683	683
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	-	-	-	-	-	-	-	-	-
11	Lake Worth Native Generation	88	88	-	-	-	-	-	-	-	-
12	Sub Total Existing Resources	1,608	1,570	1,426	1,458	1,458	1,458	1,458	1,458	1,458	1,458
	Planned Additions										
13	None Required	-	-	-	-	-	-	-	-	-	-
15	Sub Total Planned Additions	-	-	-	-	-	-	-	-	-	-
16	<b>Total Installed Capacity</b>	<b>1,608</b>	<b>1,570</b>	<b>1,426</b>	<b>1,458</b>	<b>1,458</b>	<b>1,458</b>	<b>1,458</b>	<b>1,458</b>	<b>1,458</b>	<b>1,458</b>
	<b>Firm Capacity Import</b>										
	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)	-	-	-	-	-	-	-	-	-	-
20	Sub Total Without Reserves	241	241	241	241	241	241	241	241	241	241
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	-	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	-	-	-	-	-	-	-	-	-
23	Sub Total With Reserves	45	-	-	-	-	-	-	-	-	-
24	<b>Total Firm Capacity Import</b>	<b>286</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>	<b>241</b>
25	<b>Total Available Capacity</b>	<b>1,894</b>	<b>1,811</b>	<b>1,667</b>	<b>1,699</b>	<b>1,699</b>	<b>1,699</b>	<b>1,699</b>	<b>1,699</b>	<b>1,699</b>	<b>1,699</b>

[1] The 2014 summer season nuclear value reflects the potential impact of an extended outage of Crystal River #3 and if replacement power were not provided.

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

Line No.	Resource Description (a)	Winter Rating (MW) [1]									
		2012 (b)	2013 (c)	2014 (d)	2015 (e)	2016 (f)	2017 (g)	2018 (h)	2019 (i)	2020 (j)	2021 (k)
	<b>Installed Capacity</b>										
	Existing Resources										
1	Excluded Resources (Nuclear) [2]	78	84	36	66	66	66	66	66	66	66
2	Stanton Coal Plant	186	186	178	177	180	180	180	180	180	180
3	Stanton CC Unit A	45	45	45	45	45	45	45	45	45	45
4	Cane Island 1-4	711	711	711	711	711	711	711	711	711	711
5	Indian River CTs	101	101	101	101	101	101	101	101	101	101
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	-	-	-	-	-	-	-	-	-
11	Lake Worth Native Generation	92	92	-	-	-	-	-	-	-	-
12	<b>Sub Total Existing Resources</b>	<b>1,674</b>	<b>1,635</b>	<b>1,487</b>	<b>1,517</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>
	Planned Additions										
13	None Required	-	-	-	-	-	-	-	-	-	-
15	<b>Sub Total Planned Additions</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
16	<b>Total Installed Capacity</b>	<b>1,674</b>	<b>1,635</b>	<b>1,487</b>	<b>1,517</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>	<b>1,519</b>
	<b>Firm Capacity Import</b>										
	Firm Capacity Import Without Reserves										
	Stanton A Purchase (ARP)	40	40	40	40	40	40	40	40	40	40
	Stanton A Purchase (KUA)	40	40	40	40	40	40	40	40	40	40
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	<b>Sub Total Without Reserves</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>
	Firm Capacity Import With Reserves										
21	PEF Partial Requirements	-	-	-	-	-	-	-	-	-	-
22	FPL Long-Term Partial Requirements	45	45	-	-	-	-	-	-	-	-
23	<b>Sub Total With Reserves</b>	<b>45</b>	<b>45</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
24	<b>Total Firm Capacity Import</b>	<b>304</b>	<b>304</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>	<b>259</b>
25	<b>Total Available Capacity</b>	<b>1,978</b>	<b>1,939</b>	<b>1,746</b>	<b>1,776</b>	<b>1,778</b>	<b>1,778</b>	<b>1,778</b>	<b>1,778</b>	<b>1,778</b>	<b>1,778</b>

[1] The 2012 Winter Season in this document is considered December 2011 through February 2012

[2] The 2014 Winter Season reflects the potential impact of an extended outage of Crystal River #3 during January 2014 without replacement power.

**Schedule 5  
Fuel Requirements – All-Requirements Power Supply Project**

Line No.	(1) Fuel Type	(2) Unit Type	(3) Fuel Units	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
				Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
1	Nuclear [1]		Trillion BTU	6	7	7	3	5	6	5	6	5	6	5	
2	Coal		000 Ton	374	400	451	448	459	468	469	471	481	487	491	
3	Residual	Steam	000 BBL	-	2	2	2	2	2	1	1	1	2	2	
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-	
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-	
6		Total	000 BBL	-	2	2	2	2	2	2	1	1	1	2	
7		Distillate	Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8			CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9	CT		000 BBL	11	5	-	-	-	1	2	3	3	3	3	
10	Total		000 BBL	11	5	-	-	-	1	2	3	3	3	3	
11	Natural Gas	Steam	000 MCF	-	3	-	-	-	-	-	-	-	-	-	
12		CC	000 MCF	31,454	27,945	26,261	26,730	26,496	26,730	27,393	27,291	28,030	28,657	29,408	
13		CT	000 MCF	443	145	103	107	113	129	135	177	179	185	203	
14		Total	000 MCF	31,896	28,094	26,364	26,837	26,609	26,858	27,527	27,468	28,209	28,842	29,611	
15	Renewables [2]	Biofuels	Billion BTU	214	130	130	130	130	130	130	130	130	130	130	
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
18		Hydro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
19		Landfill Gas	Billion BTU	151	222	203	178	164	155	146	137	128	119	110	
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-	
24		Total	Billion BTU	366	352	333	308	294	285	276	267	258	249	240	
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-	

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

Line No.	(1) Energy Source	(2) Prime Mover	(3) Units	(4) through (14)										
				Actual 2011	(5) 2012	(6) 2013	(7) 2014	(8) 2015	(9) 2016	(10) 2017	(11) 2018	(12) 2019	(13) 2020	(14) 2021
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	535	619	656	303	499	512	499	526	483	528	499
3	Coal		GWh	989	1,015	1,163	1,160	1,188	1,214	1,217	1,223	1,249	1,265	1,276
4	Residual		GWh	-	-	-	-	-	-	-	-	-	-	-
5		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
7		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
8	Distillate		GWh	-	-	-	-	-	-	-	-	-	-	-
9		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
11		CT	GWh	5	2	-	-	-	0	1	1	1	1	2
11		Total	GWh	5	2	-	-	-	0	1	1	1	1	2
12	Natural Gas		GWh	-	0	-	-	-	-	-	-	-	-	-
13		Steam	GWh	-	0	-	-	-	-	-	-	-	-	-
14		CC	GWh	4,309	3,882	3,624	3,706	3,637	3,632	3,712	3,727	3,826	3,900	4,015
15		CT	GWh	33	11	8	8	8	9	10	13	14	13	16
15		Total	GWh	4,342	3,894	3,632	3,713	3,646	3,642	3,722	3,741	3,839	3,913	4,031
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
17	Renewables [2]		GWh	21	13	13	13	13	13	13	13	13	13	13
18		Biofuels	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Hydro	GWh	-	-	-	-	-	-	-	-	-	-	-
22		Landfill Gas	GWh	16	23	21	19	17	16	15	14	13	12	12
23		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	37	36	34	32	30	29	28	27	26	25	25
27	Interchange		GWh	240	665	647	814	772	731	768	829	862	846	860
28	Net Energy for Load [3]		GWh	6,128	6,231	6,333	6,021	6,135	6,128	6,236	6,347	6,461	6,580	6,692

[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)		(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	8.7	9.9	10.4	5.0	8.1	8.3	8.0	8.3	7.5	8.0	7.5	
3	Coal		%	15.8	16.3	18.4	19.3	19.4	19.8	19.5	19.3	19.3	19.2	19.1	
	Residual														
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-	
5		CC	%	-	-	-	-	-	-	-	-	-	-	-	
6		CT	%	-	-	-	-	-	-	-	-	-	-	-	
7		Total	%	-	-	-	-	-	-	-	-	-	-	-	
	Distillate														
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-	
9		CC	%	-	-	-	-	-	-	-	-	-	-	-	
10		CT	%	0.1	0.0	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	
11		Total	%	0.1	0.0	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	
	Natural Gas														
12		Steam	%	-	0.0	-	-	-	-	-	-	-	-	-	
13		CC	%	70.3	62.3	57.2	61.5	59.3	59.3	59.5	58.7	59.2	59.3	60.0	
14		CT	%	0.5	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	
15		Total	%	70.9	62.5	57.4	61.7	59.4	59.4	59.7	58.9	59.4	59.5	60.2	
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		Hydro	%	-	-	-	-	-	-	-	-	-	-	-	
21		Landfill Gas	%	0.3	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	
22		MSW	%	-	-	-	-	-	-	-	-	-	-	-	
23		Solar	%	-	-	-	-	-	-	-	-	-	-	-	
24		Wind	%	-	-	-	-	-	-	-	-	-	-	-	
25		Other	%	-	-	-	-	-	-	-	-	-	-	-	
26		Total	%	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	
27	Interchange		%	3.9	10.7	13.4	13.5	12.6	11.9	12.3	13.1	13.3	12.9	12.9	
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)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW)	Firm Capacity Export (MW) [2]	QF (MW)	Total Available Capacity (MW)	Total System Firm Summer 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)
2012	1,608	286	0	0	1,894	1,291	41	1,332	562	44%	0	562	44%
2013	1,570	241	0	0	1,811	1,313	42	1,355	456	34%	0	456	34%
2014	1,426	241	0	0	1,667	1,252	39	1,291	376	29%	0	376	29%
2015	1,458	241	0	0	1,699	1,277	39	1,316	383	29%	0	383	29%
2016	1,458	241	0	0	1,699	1,273	40	1,313	386	29%	0	386	29%
2017	1,458	241	0	0	1,699	1,295	41	1,336	363	27%	0	363	27%
2018	1,458	241	0	0	1,699	1,320	41	1,361	338	25%	0	338	25%
2019	1,458	241	0	0	1,699	1,343	42	1,385	314	23%	0	314	23%
2020	1,458	241	0	0	1,699	1,368	43	1,411	288	20%	0	288	20%
2021	1,458	241	0	0	1,699	1,392	44	1,436	263	18%	0	263	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 calculated as  $[(\text{Total Available Capacity} - \text{Partial Requirements Purchases}) - (\text{System Firm Peak Demand} - \text{Partial Requirements Purchases})] / (\text{System Firm Peak Demand} - \text{Partial Requirements Purchases})$ . 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)			
2011/12	1,674	304	0	0	1,978	1,180	39	1,257	721	59%	0	721	59%			
2012/13	1,635	304	0	0	1,939	1,199	39	1,278	661	54%	0	661	54%			
2013/14	1,487	259	0	0	1,746	1,156	37	1,229	517	42%	0	517	42%			
2014/15	1,517	259	0	0	1,776	1,177	38	1,253	523	42%	0	523	42%			
2015/16	1,519	259	0	0	1,778	1,174	38	1,251	527	42%	0	527	42%			
2016/17	1,519	259	0	0	1,778	1,195	39	1,273	505	40%	0	505	40%			
2017/18	1,519	259	0	0	1,778	1,217	40	1,296	482	37%	0	482	37%			
2018/19	1,519	259	0	0	1,778	1,240	40	1,320	458	35%	0	458	35%			
2019/20	1,519	259	0	0	1,778	1,262	41	1,344	434	32%	0	434	32%			
2020/21	1,519	259	0	0	1,778	1,284	42	1,367	410	30%	0	410	30%			

[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 calculated as  $\frac{((\text{Total Available Capacity} - \text{Partial Requirements Purchases}) - (\text{System Firm Peak Demand} - \text{Partial Requirements Purchases}))}{(\text{System Firm Peak Demand} - \text{Partial Requirements Purchases})}$ . 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	
<b>Resource Additions</b>														
<b>Changes to Existing Resources</b>														
Hansel Plant	21	Osceola	CT	NG	-	PL	-	NA	02/83	09/12	38	(28)	(34)	RT
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	09/12	8	(8)	(5)	RT
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	09/12	8	(8)	(5)	RT
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	NA	10/12	NA	NA	8	8	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)	(22)	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]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	NA	11/13	NA	NA	2	2	A [3]
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	NA	05/14	NA	NA	(1)	(1)	A [2]
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	NA	05/15	NA	NA	2	2	A [3]
Crystal River	3	Citrus	NP	UR	-	TK	-	NA	11/14	NA	NA	7	7	A

[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.  
 [2] Decrease due to addition of SCR/FGD system.  
 [3] Capacity increases to Stanton 1 and Stanton 2 from unit efficiency improvements.



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 sites for FMPA as specified by PSC/EAG 43.

- Cane Island Power Park –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 683 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. In 2011, FMPA completed the construction of Cane Island Unit 4 (CI4), a nominal 300 MW (summer rating), natural gas-fired 1x1 GE 7FA combined cycle unit wholly owned by the ARP. The commercial operation date of CI4 was July 12, 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 any proposed ARP generating facility, if applicable. 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)**

**(No Proposed Generating Facilities)**

(1)	Plant Name and Unit Number	
(2)	Capacity a. Summer b. Winter	
(3)	Technology Type	
(4)	Anticipated Construction Timing a. Field Construction Start Date b. Commercial In-Service Date	
(5)	Fuel a. Primary Fuel b. Alternate Fuel	
(6)	Air Pollution Control Strategy	
(7)	Cooling Method	
(8)	Total Site Area	
(9)	Construction Status	
(10)	Certification Status	
(11)	Status with Federal Agencies	
(12)	Projected Unit Performance Data Planned Outage Factor (POF) Forced Outage Factor (FOF) Equivalent Availability Factor Resulting Capacity Factor Average Net Operating Heat Rate (ANOHR)	
(13)	Projected Unit Financial Data Book Life (Years) Total Installed Cost (In-Service Year \$/kW) Direct Construction Cost (2010 \$/kW) AFUDC Amount (\$/kW) [1] Escalation (\$/kW) Fixed O&M (\$/kW) Variable O&M (\$/MWh)	

[1] Includes AFUDC and bond issuance expenses



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

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

Note: FMPA currently has no new proposed transmission lines.



Florida Municipal Power Agency

# Appendix I

## List of Abbreviations

Community Power + Statewide Strength ®

## Appendix I List of Abbreviations

### Generator Type

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

### Fuel Type

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

### Fuel Transportation Method

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water Transportation

### Status of Generating Facilities

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

### Other

NA	Not Available or Not Applicable
----	---------------------------------



Florida Municipal Power Agency

# Appendix II

## ARP Participant Transmission Information

Community Power + Statewide Strength®

---

**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  
2012 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			13.8 kV		6/2012
	STATCOM/Shunt Capacitor at Stock Island Substation			13.8 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	Osceola Parkway Substation	Osceola Parkway Osceola Parkway		69 kV	1 1	6/2017
	Lake Bryan		69 kV	6/2017		
	Lake Cecile		69 kV	6/2017		
	Domingo Toro Substation		69 kV	6/2019		
Ocala	Shaw Second 30 MVA Transformer		30	69/12.47 kV	1	6/2017



Florida Municipal Power Agency

# Appendix III

## Additional Reserve Margin Information

Community Power + Statewide Strength ®

### Appendix III Additional Reserve Margin Information

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

**Table III-1  
Calculation of Reserve Margin at Time of Summer Peak  
All-Requirements 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)
2012	1,894	1,333	45	561	44%
2013	1,811	1,355	0	456	34%
2014	1,667	1,291	0	376	29%
2015	1,699	1,316	0	383	29%
2016	1,699	1,313	0	386	29%
2017	1,699	1,336	0	363	27%
2018	1,699	1,361	0	338	25%
2019	1,699	1,385	0	314	23%
2020	1,699	1,411	0	288	20%
2021	1,699	1,436	0	263	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)
2011/12	1,978	1,257	45	721	59%
2012/13	1,939	1,278	45	661	54%
2013/14	1,746	1,229	0	517	42%
2014/15	1,776	1,253	0	523	42%
2015/16	1,778	1,251	0	527	42%
2016/17	1,778	1,273	0	505	40%
2017/18	1,778	1,296	0	482	37%
2018/19	1,778	1,320	0	458	35%
2019/20	1,778	1,344	0	434	32%
2020/21	1,778	1,367	0	410	30%

[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)



Florida Municipal Power Agency  
Community Power. Statewide Strength. •

Florida Municipal Power Agency  
8553 Commodity Circle  
Orlando, FL 32819-9002  
[www.fmpa.com](http://www.fmpa.com)

---