ORIGINAL

Florida Municipal Power Agency

William "Bill" May
Planning and Contracts Manager

March 31, 2006

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

RECEIVED-FPSC
06 MAR 31 AM 8:41
COMMISSION CLERK

Dear Ms. Bayo:

Enclosed are 25 copies of Florida Municipal Power Agency's April 2006 Ten-Year Site Plan as prepared and submitted by R.W. Beck (RWB) on behalf of FMPA.

The Ten-Year Site Plan information is provided in accordance with Florida Public Service Commission rule 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan. The plan is required to describe the estimated electric power generating needs and to identify the general location of any proposed near-term power plant sites as of December 31, 2005.

If you should have any questions, please feel free to contact me at 321-239-1033.

Sincerely,

William S. May

William May
Planning and Contracts Manager

Enclosure

WM/mle

XC: Michael Haff (FPSC)
Nicholas Guarriello (RW Beck)
Fred Bryant (FMPA)
Rick Casey (FMPA)

CMP ___
COM ___
CTR ___
ECR ___
GCL ___
OPC ___
RCA ___
SCR ___
SGA ___
SEC 1
OTH K. Pena (2)

DISTRIBUTION CENTER
06 MAR 31 AM 7:53

DOCUMENT NUMBER-DATE
02850 MAR 31 06
FPSC-COMMISSION CLERK

8553 Commodity Circle | Orlando, FL 32819-9002
T. (407) 355-7767 | Toll Free (888) 774-7606
F. (407) 355-5794 | www.fmpa.com
bill.may@fmpa.com

Florida Municipal Power Agency

Ten-Year Site Plan

April 2006

Community Power + Statewide Strength

Florida Municipal Power Agency

Ten-Year Site Plan 2006-2015

Submitted to

Florida Public Service Commission

April 1, 2006

Community Power + Statewide Strength

Florida Municipal Power Agency

Table of Contents

Community Power + Statewide Strength

Table of Contents

List of Figures, Tables and Required Schedules

Florida Municipal Power Agency

Executive Summary

Community Power + Statewide Strength

Executive Summary

The following information is provided in accordance with Florida Public Service Commission (PSC) Rules 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan (TYSP). The TYSP is required to describe the estimated electric power generating needs and to identify the general location and type of any proposed near-term generation capacity and transmission additions.

The Florida Municipal Power Agency (FMPA, or the Agency) is a project-oriented, joint-action agency. FMPA's direct responsibility for power supply planning can be separated into two parts. First, for the All-Requirements Project (ARP), where the Agency has committed to supplying all of the power requirements of 15 cities, the Agency is solely responsible for power supply planning. Second, for member systems that are not in the ARP, the Agency's role has been to evaluate joint action opportunities and make the findings available to the membership whereby each member can elect whether or not to participate. This report presents information on the existing Agency projects and planning information for the ARP.

The ARP summer capacity resources for the year 2006 total 1,753 MW. FMPA is currently constructing a 42 MW peaking unit at Key West and is in the final approval process for a 296 MW combined cycle unit at the Treasure Coast Energy Center site near Fort Pierce. The in-service date for the Stock Island peaking unit is scheduled for June 2006, and the Treasure Coast Energy Center combined cycle unit is scheduled for an in-service date of June 2008. In addition, FMPA is planning to purchase 157 MW of new peaking power from Southern Company's Oleander facility beginning December 2007. Future ARP TYSP expansion resources are presented in Table ES-1.

Worthy of note is FMPA's awareness of the potential benefits of increased fuel diversity among its generating portfolio, which has prompted FMPA to proceed with three other municipal utilities in the development of the Taylor Energy Center. Current information on the Taylor Energy Center can be found at the Web site www.taylorenergycenter.org. Commercial operation of such a unit, if ultimately constructed, is currently scheduled for the summer of 2012 at the earliest.

Table ES-1
FMPA TYSP Planned Expansion Resources

Unit Description	Commercial Operation (MM/YY)	Summer Capacity (MW)
Stock Island CT4	06/06	42
Peaking Purchase [2]	06/07	25
Southern Company Peaking Purchase	12/07	157
Treasure Coast Energy Center Unit 1	06/08	296
Unsited Peaking Units [1]	06/10	84
Peaking Purchase [2]	06/11	62
Taylor Energy Center Unit 1	06/12	288
Peaking Purchase [2]	06/13	42
Unsited Combined Cycle Unit	06/14	296

[1] Two combustion turbine units.

[2] This purchase is intended to fulfill 18% planning reserves for the summer of the purchase year.

Florida Municipal Power Agency

Section 1.0

Description of FMPA

Community Power + Statewide Strength

1.0 Description of FMPA

1.1 FMPA

FMPA is a wholesale power company created to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements and is owned by 29 municipal electric utilities. FMPA also provides economies of scale in power generation and related services to support community-owned electric utilities.

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members to provide a means by which its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. This agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution, the Joint Power Act, Chapter 361, Part II, Florida Statutes, and the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes.

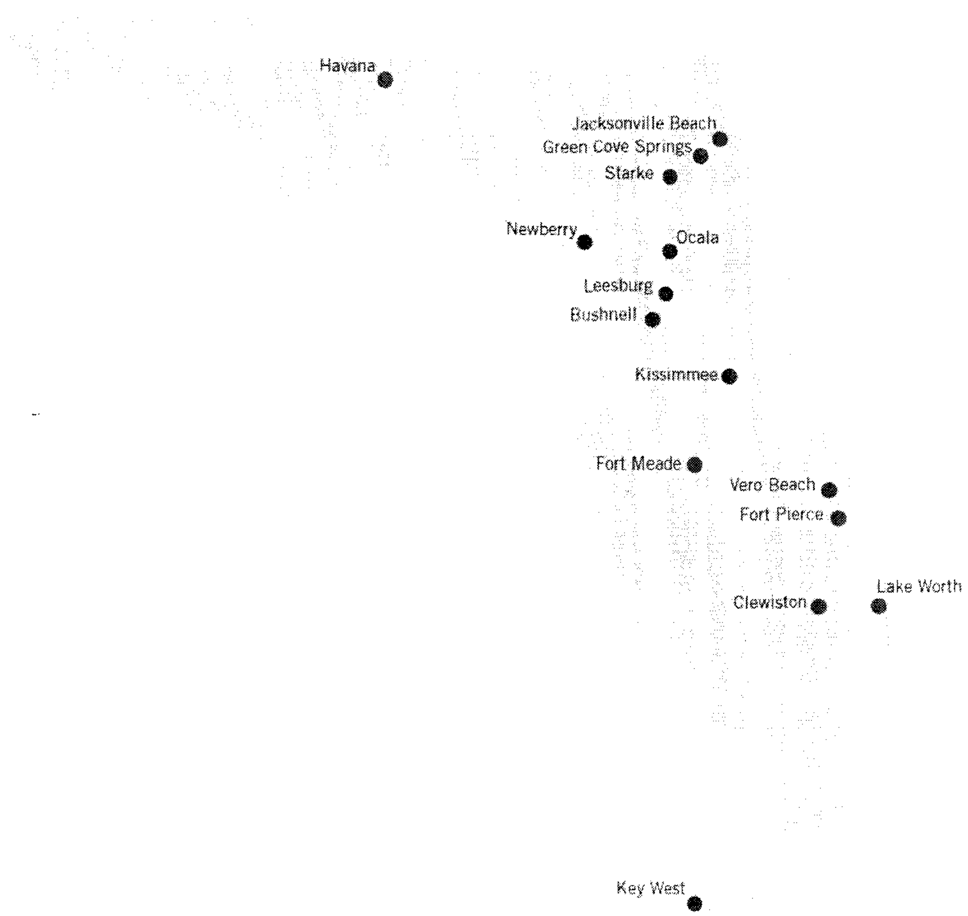
The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on the basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each city commission, utility commission, or authority, which is a signatory to the Interlocal Agreement, has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and General Counsel, establishing bylaws that govern how FMPA operates, and creating policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer, and an Executive Committee. The Executive Committee consists of 13 representatives, which include nine elected by the Board, the current Board Chairman, Vice Chairman, Secretary, and Treasurer. The Executive Committee meets regularly to control FMPA's day-to-day operations and to approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

1.2 All-Requirements Project

FMPA developed the All-Requirements Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the needs of the ARP members. Of the 29 FMPA member municipals, 15 are served by the ARP, as shown in Figure 1-1. Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP members. Clewiston joined in 1991. In 1997, the cities of Vero Beach and Starke joined the ARP. In 1998, FPUA and Key West joined the ARP. The City of Fort Meade, the Town of Havana, and the City of Newberry joined in 2000. In 2002, KUA and Lake Worth joined the ARP. Vero Beach has provided notice to FMPA to exercise their right to exit the ARP as a full requirements member beginning January 1, 2010. A map illustrating the location of the ARP members is shown below as Figure 1-1.

Figure 1-1
FMPA Member Cities



ARP members, both with and without their own generating capacity, are required to purchase all their capacity and energy from the ARP. ARP members with their own generating capacity are required to sell the electric capacity and energy of their generating resources to FMPA. In exchange for the sale of their electric capacity and energy, the generating members receive capacity and energy (C&E) payments from ARP members.

The ARP serves customer accounts in the following 15 municipalities. The following information is based on the Florida Municipal Electric Association's 2005 membership directory (www.publicpower.com) and additional information obtained during 2005.

Bushnell

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

Clewiston

The City of Clewiston is located in southern Florida in Hendry County. The City joined the ARP in May 1991. Kevin McCarthy is the Utilities Director. The City's service area is approximately 5 square miles. For more information about the City of Clewiston, please visit www.clewiston-fl.gov.

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City electric department serves 2,605 customers with a total load of 12 MW. The City joined the ARP in February 2000. Katrina Powell is the City Manager. The City's service area is approximately 5 square miles. FMPA serves capacity and energy requirements for the City, via the full requirements agreement currently in place with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the City from the ARP's portfolio of power supply resources. For more information about the City of Fort Meade, please visit www.state.fl.us/ftmeade/.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. The Fort Pierce Utilities Authority (FPUA) serves 25,550 customers with a total load of 124 MW. FPUA joined the ARP in January 1998. Elie J. Boudreaux III, P.E., is the Director of Utilities and Thomas W. Richards, P.E., is Director of Electric & Gas Systems. FPUA's service area is approximately 35 square miles. For more information about Fort Pierce Utilities Authority, please visit www.fpua.com.

Green Cove Springs

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

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. The town electric department serves 1,293 customers with a total load of 6 MW. The Town joined the ARP in July 2000. Susan J. Freiden is the Town Manager. The Town's service area is approximately 4.5 square miles. For more information about the Town of Havana, please visit www.havanaflorida.com.

Jacksonville Beach

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

Utility Board, City of Key West

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

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. The Kissimmee Utility Authority (KUA) serves 51,300 customers with a total load of 285 MW. KUA joined the ARP in October 2002. James C. Welsh is the President & General Manager, and A. K. (Ben) Sharma is Vice President of Power Supply. KUA's service area is approximately 85 square miles. For more information about Kissimmee Utility Authority, please visit www.kua.com.

Lake Worth

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

Leesburg

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

Newberry

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

Ocala

The City of Ocala is located in central Florida in Marion County. The City joined the ARP in May 1986. Paul K. Nugent is the City Manager, and Rebecca Mattey is the Director of Electric Utility. The City's service area is approximately 161 square miles. For more information about the City of Ocala, please visit www.ocalafl.org.

Starke

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

Vero Beach

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

On December 9, 2004, the City of Vero Beach sent FMPA their "Notice of Establishment of Contract Rate of Delivery." The effect of the notice is that the ARP will no longer utilize the City's generating resources, and the ARP will commence serving Vero Beach on a partial requirements basis. The effective date of the notice is January 1, 2010.

For more information about the City of Vero Beach, please visit www.covb.org.

1.3 FMPA Other Generation Projects

FMPA has four other power supply projects in operation in addition to the ARP as discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit. The St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of FMPA's members are participants in the St. Lucie Project, with the following entitlements as shown in Table 1-1.

Table 1-1
St. Lucie Project Participants

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

Stanton Project

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

Table 1-2
Stanton Project Participants

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

Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of FMPA's members are participants in the Tri-City Project with the following entitlements as shown in Table 1-3.

Table 1-3
Tri-City Project Participants

City	% Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

Stanton II Project

On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2367 percent undivided ownership interest in OUC's Stanton Unit No. 2, a coal fired unit virtually identical to Stanton Unit No. 1. The unit commenced commercial operation in June 1996. Seven of FMPA's members are participants in the Stanton II Project with the following entitlements as shown in Table 1-4.

Table 1-4
Stanton II Project Participants

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

1.4 Summary of Projects

Table 1-5 provides a summary of FMPA member project participation as of January 1, 2006.

Table 1-5
Summary of FMPA Power Supply Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X			X	
Ft. Pierce Utilities Authority	X	X	X	X	X
City of Green Cove Springs	X			X	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X		X	X
City of Lake Worth	X	X		X	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X

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

Florida Municipal Power Agency

Section 2.0

Description of Existing Facilities

Community Power + Statewide Strength

2.0 Description of Existing Facilities

2.1 ARP Supply-Side Resources

The ARP supply-side resources consist of a diversified mix of generation ownership, purchase power, and fuel supply. The supply side resources for the ARP for the 2006 summer season are shown by ownership capacity in Table 2-1

Table 2-1
ARP Supply-Side Resources
Summer 2006

Resource Category	Summer Capacity (MW)
1) Nuclear	84
2) ARP Ownership	
Existing	521
New	42
Sub Total ARP Ownership	563
3) Member Ownership	
Fort Pierce	110
KES	41
KUA	292
Lake Worth	87
Vero Beach	137
Sub Total Member Ownership	666
4) Purchase Power	439
Total 2006 ARP Resources	1,753

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

1) **Nuclear Generation:** A number of the ARP members own small amounts of capacity in Progress Energy Florida's Crystal River Unit 3. Likewise, a number of ARP members participate in the St. Lucie Project, which provides them capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of the capacity and energy from these units. The ARP provides the

balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

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

3) **Member Owned Generation:** Capacity included in this category is generation owned by the ARP members either solely or jointly. The ARP purchases this capacity from the ARP members and then commits and dispatches the generation to meet the total requirements of the ARP.

4) **Purchase Power Generation:** This category includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members which were entered into prior to the member joining the ARP. Purchase power generation includes capacity and energy received from other suppliers such as Progress Energy Florida (PEF), FPL, OUC, Lakeland Electric, Gainesville Regional Utilities (GRU), Calpine, and Southern Company.

2.2 ARP Transmission System

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

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

2.2.1 Member Transmission Systems

Fort Pierce Utility Authority

Fort Pierce Utility Authority (FPUA) is a municipally owned utility operating electric, water, wastewater, and natural gas utilities. The electric utility operates an internal, looped, 69kV transmission system for system load and a 118 MW local power generating plant. There are two interconnections with other utilities, both operated at 138 kV. The FPUA's Hartman Substation interconnects to FPL's Midway and Emerson Substations. The second interconnection is from the FPUA's Garden City (#2) Substation to County Line Substation No. 20, connected by a 7.5 mile, single circuit, 138 kV line operated and maintained by FPUA. County Line Substation is connected by two separate, single circuits, 138 kV transmission lines to FPL's Emerson Substation and the City of Vero Beach's South Substation. County Line Substation and the connecting lines to Emerson and South Substations are operated by the City of Vero Beach. FPUA and the City of Vero Beach jointly own County Line Substation, the 138 kV line connecting to Emerson Substation, and some parts of the tie between the two cities.

Keys Energy Services

KEYS of The Utility Board of the City of Key West owns, operates, 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. KEYS owns and operates a 49.2 mile long 138 kV transmission line from Marathon Substation to KEYS' Stock Island Substation. The line loops in and out of KEYS' Big Pine and Big Coppitt Substations. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has five 69 kV and four 138 kV substations which supply power at 13.8 kV and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV and 2 miles of 4.16 kV distribution line.

City of Lake Worth Utilities

The City of Lake Worth Utilities (LWU) owns, operates and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy in and around the City of Lake Worth. The total generating capability, located at the Tom G. Smith power-generating plant is rated at approximately 86 MW. LWU has one 138 kV interconnection with FPL at the LWU owned Hypoluxo Switching Station. A 3-mile 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4-mile 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 operates an internal 26 kV sub-transmission system to serve system load.

Kissimmee Utility Authority

KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines. KUA serves a total area of approximately 85 square miles. KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO and the City of St. Cloud. KUA owns and operates 22 miles of 230 kV and 41 miles of 69 kV transmission lines. KUA and FMPA jointly own 21.4 miles of 230 kV lines out of Cane Island Power Park. Electric capacity and energy supplied from KUA owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to nine distribution substations. KUA has direct transmission interconnections with: (1) PEF at PEF's 69 kV Lake Bryan Substation and 69 kV Meadow Wood South Substation; (2) OUC at OUC's 230 kV Taft Substation and TECO / OUC's 230 kV Osceola Substation from Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

City of Ocala Electric Utility

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

OEU's 230kV transmission system interconnects with PEF's and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs to Silver Springs North 230 kV tie lines. OEU's Dearmin Substation ties at PEF's Silver Springs Substation and OEU's Ergle Substation ties at SECI's Silver Springs North Switching Station. OEU also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OEU operates a 13 mile 230 kV transmission line from Ergle Substation to Shaw Substation. OEU is planning to add a second 230 kV tie by rerouting the existing Shaw to Ergle 230 kV line from Shaw Substation to SECI's Silver Springs North Switching Station.

City of Vero Beach

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

2.2.2 ARP Transmission Agreements

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

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

Schedule 1
ARP Existing Generating Resources as of December 31, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Nuclear Capacity												
Crystal River	3	Citrus	NP	UR	-	TK	-	03/77	NA	891	24	25
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	60	61
Total Nuclear Capacity											84	86
ARP-Owned Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	102	102
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	101	101
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	21	23
Indian River	CT A	Brevard	CT	NG	DFO	PL	TK	06/89	NA	41	14	18
Indian River	CT B	Brevard	CT	NG	DFO	PL	TK	07/89	NA	41	14	18
Indian River	CT C	Brevard	CT	NG	DFO	PL	TK	08/92	NA	112	22	26
Indian River	CT D	Brevard	CT	NG	DFO	PL	TK	10/92	NA	112	22	26
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	15
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	55	60
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	123	125
Stock Island	CT 2	Monroe	CT	DFO	-	WA	-	06/99	NA	21	15	18
Stock Island	CT 3	Monroe	CT	DFO	-	WA	-	06/99	NA	21	15	18
Total ARP-Owned Generation											521	551
Member-Owned Generation												
Vero Beach												
Municipal Plant	1	Indian River	ST	NG	RFO	PL	TK	11/61	NA	13	12	12
Municipal Plant	2	Indian River	CA	NG	RFO	PL	TK	08/64	NA	13	12	13
Municipal Plant	3	Indian River	ST	NG	RFO	PL	TK	09/71	NA	33	30	34
Municipal Plant	4	Indian River	ST	NG	RFO	PL	TK	08/76	NA	56	51	56
Municipal Plant	5	Indian River	CT	NG	RFO	PL	TK	12/92	NA	40	32	40
Sub Total Vero Beach											137	155
Fort Pierce Utilities Authority												
H.D. King	5	St. Lucie	CA	WH	-	-	-	01/53	05/08	8	8	8
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	01/64	05/08	32	24	32
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	05/76	05/08	50	50	50
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	05/90	05/08	23	23	23
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	3	3
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	04/70	05/08	3	3	3
Sub Total Fort Pierce											110	118

Schedule 1 (Continued)
ARP Existing Resources as of December 31, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Type		Fuel Transportation		Commercial In-Service	Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Kissimmee Utility Authority												
Hansel Plant	21	Osceola	CT	NG	DFO	PL	TK	02/83	12/11	38	16	15
Hansel Plant	22	Osceola	CA	WH	-	-	-	11/83	12/11	8	16	15
Hansel Plant	23	Osceola	CA	WH	-	-	-	11/83	12/11	8	16	15
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	17	15
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	55	60
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	123	125
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	A	Brevard	CT	NG	DFO	PL	TK	06/89	NA	41	4	6
Indian River	B	Brevard	CT	NG	DFO	PL	TK	06/89	NA	41	4	6
Sub Total KUA											292	300
Lake Worth												
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	12/76	06/12	31	26	31
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	03/78	06/12	20	20	22
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	12/65	06/12	2	2	2
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	11/67	06/12	27	22	24
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	03/78	06/12	10	8	10
Sub Total Lake Worth											87	97
Keys Energy Services												
Big Pine Key	1	Monroe	IC	DFO	-	TK	-	02/69	02/06	3	0	3
Cudjoe Key Peaker	2	Monroe	IC	DFO	-	TK	-	08/68	02/06	3	0	2
Cudjoe Key Peaker	3	Monroe	IC	DFO	-	TK	-	08/68	02/06	2	0	2
Stock Island	GT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	18	20
Stock Island HSD	IC1	Monroe	IC	DFO	-	WA	-	1/65	NA	2	2	2
Stock Island HSD	IC2	Monroe	IC	DFO	-	WA	-	1/65	NA	2	2	2
Stock Island HSD	IC3	Monroe	IC	DFO	-	WA	-	1/65	NA	2	2	2
Stock Island MSD	MSD1	Monroe	IC	DFO	-	WA	-	6/91	NA	9	9	9
Stock Island MSD	MSD2	Monroe	IC	DFO	-	WA	-	6/91	NA	9	9	9
Sub Total Keys											41	50
Total Member-Owned Generation											666	721
Total Generation Resources											1,271	1,357

Florida Municipal Power Agency

Section 3.0

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

Community Power + Statewide Strength

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

3.1 Introduction

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

3.2 Load Forecast Process

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

In addition to the base case load and energy forecast, FMPA has prepared high and low case forecasts for each of the ARP members, which are intended to capture the majority of the uncertainty of certain driving variables. 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 2005 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2005 through 2024. The Forecast relied upon municipal utility data provided to FMPA by the ARP members and load data maintained by FMPA. The Forecast includes information based upon the City of Vero Beach providing notice to FMPA that the City would serve its own load requirements beginning January 1, 2010. The forecast does not currently include the partial requirements load referred to in Section 1.2 of this document that may be served by FMPA beginning January 1, 2010. Historical and projected economic and demographic data was provided by Economy.com, a nationally recognized provider of such data. The forecast also relied on information regarding local economic and demographic issues specific to each ARP member.

The results of the Forecast show that the calendar year net energy for load supplied from the ARP is expected to grow at an annual average growth rate of 1.0% percent from 2006-2015, which growth rate reflects the loss of load associated with the withdrawal of Vero Beach from the ARP in 2010, and 1.9% percent from 2016-2024. On a normal weather basis, the Base Case projected calendar year 2006 net energy for load and coincident peak supplied from the ARP are 7,317 GWh and 1,467 MW, respectively (excluding east transmission losses).

In addition to the Base Case Forecast, FMPA has prepared high and low forecasts to separately capture the uncertainty of economic activity and the uncertainty of weather. The high (Severe) and low (Mild) weather cases result in forecast loads which are approximately 4.0% above and 3.7% below the Base Case, respectively, throughout the forecast horizon.

3.4 Methodology

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

In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures (e.g., standard error, adjusted R-squared, Schwarz Information Criterion, LJung-Box test, etc.). Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. The ability of a model to explain historical variation is often referred to as "goodness-of-fit." These historical relationships are generally assumed to continue into the future, barring any specific information or assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

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

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

3.4.1 Model Specification

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

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. The residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers, (ii) real personal income per household, (iii) real electricity prices, and (iv) weather variables. The number of residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the ARP members and the number of households in each ARP member's county.

For the general service class models, the econometric models reflect that energy requirements are best explained by: (i) real retail sales, total personal income, or gross domestic product (GDP) as a measure of economic activity and population in and around the member's service territory, (ii) the real price of electricity, and (iii) weather variables. In the case of the general service non-demand class, retail sales was typically selected as the long-term driving variable either because it performed better by certain measures, or because the resulting forecast was more sensible. Similarly, for the general service demand class, total personal income was typically selected. For the industrial class, GDP was the typical long-term driving variable, except in cases where the forecast was based on an assumption to address a single or few general service demand customers (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 are summed to equal the total sales of each ARP member. An assumed loss factor, typically based on a 5-year average of historical loss factors, is then applied to the total sales to derive monthly NEL. To the extent historical loss factors were deemed anomalous, they were excluded from these averages.

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted net energy for load on a total member system basis. The projected load factors are based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1995-2004 (i.e., a 10-year average).

Monthly peak demand is based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflects that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the ARP member groups, and the transmission providers were derived from monthly coincidence factors averaged generally over a 5-year period (2000-2004). The historical coincidence factors are based on historical coincident peak demand data that is maintained by FMPA. Similarly, the timing of the total ARP and ARP member group peaks was determined from an appropriate summation of the hourly load data.

3.5 Data Sources

3.5.1 Historical Member Retail Sales Data

Data was generally available and analyzed over January 1992, or the year a new member joined the ARP, through the end of fiscal year 2004 (i.e., September 2004) (the Study Period). Data included historical customers and sales by rate classification for each of the members. However, for a small part of the Study Period, only total revenues were available.

3.5.2 Weather Data

Historical weather data was provided by the National Climatic Data Center (a division of the National Oceanic and Atmospheric Administration) (NCDC), which was generally used to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was obtained, were selected by their quality and proximity to the ARP members. In most cases, the closest first-order weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data. In three cases (Beaches Energy Services, serving Jacksonville Beach, Fort Pierce, and Vero Beach), however, weather data from a cooperative weather station, which was closer than the closest first-order station, appeared to more accurately reflect the weather conditions that affect the ARP members' loads, based on statistical measures, than the closest first-order weather station.

The influence on electricity sales of weather has been represented through the use of two data series: heating and cooling degree days (HDD and CDD, respectively). Degree days are derived by comparing the average daily temperature and a base temperature, 65 degrees Fahrenheit. To the extent the average daily temperature exceeds 65 degrees Fahrenheit, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDD result from average daily temperatures which are below 65 degrees Fahrenheit. Heating and cooling degree days are then summed over the period of interest, in this case, months. The majority of this monthly data was obtained directly from the NDCD rather than calculated from daily data.

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

3.5.3 Economic Data

Economy.com, a nationally recognized provider of economic data, provided both historical and projected economic and demographic data for each of the 15 counties in which ARP members' service territories reside. These data included county population, households, employment, personal income, retail sales, and gross domestic product. Although all of the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales.

3.5.4 Real Electricity Price Data

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

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the ARP net energy for load is expected to grow at an annual average growth rate of 1.0 percent from 2006 through 2015, which growth rate reflects the loss of load associated with the withdrawal of Vero Beach from the ARP in 2010, and 1.9 percent from 2016-2024. On a normal weather basis, the calendar year 2006 net energy for load and coincident peak supplied from the ARP are projected to be 7,317 GWh and 1,467 MW (summer peak), respectively.

3.6.2 Uncertainty of the Forecast

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

In addition to the Base Case forecast, which relies on normal weather conditions, FMPA has developed high and low forecasts, referred to herein as the Severe and Mild weather cases, intended to capture the volatility resulting from weather variations equivalent to 90% 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.

The potential weather variability was developed using weather data specific to each weather station generally over the period 1981-2003. The uncertainty of HDD and CDD has been reduced somewhat from independent statistics to account for the typically strong, negative correlation between the two. In other words, the variation assumed is intended to reflect *annual* variability rather than the variability specific to any season. Therefore, while the summer or winter season may be more severe than assumed, the opposite season is more likely to be milder.

Finally, the weather assumptions reflect that the variability of seasonal weather among the weather stations is perfectly correlated. While this is not generally the case in continuous data, the correlation increases dramatically at the extremes. In other words, the years of extreme weather, mild or severe, tend to be widespread.

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, load forecast, and Schedules 3.1b through 3.3b present the low, or Mild weather, load forecast. Schedule 4 presents the Base Case monthly load forecast.

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1996	NA	NA	1,072	77,423	13,840	622	13,517	46,024
1997	NA	NA	1,242	93,149	13,336	833	16,710	49,829
1998	NA	NA	1,977	143,049	13,822	1,593	26,001	61,276
1999	NA	NA	1,980	151,885	13,035	1,652	27,774	59,465
2000	NA	NA	2,065	154,942	13,326	1,721	28,456	60,480
2001	NA	NA	2,105	156,857	13,422	1,750	29,015	60,298
2002	NA	NA	2,426	174,357	13,913	1,996	32,415	61,589
2003	NA	NA	3,180	227,795	13,958	2,603	41,840	62,218
2004	NA	NA	3,133	232,845	13,454	2,612	41,706	62,639
2005	NA	NA	3,235	237,776	13,607	2,692	44,405	60,614
2006	NA	NA	3,289	242,610	13,557	2,752	43,982	62,567
2007	NA	NA	3,356	246,604	13,608	2,822	44,610	63,264
2008	NA	NA	3,425	250,692	13,663	2,892	45,271	63,875
2009	NA	NA	3,529	257,373	13,710	2,969	46,401	63,978
2010	NA	NA	3,191	232,764	13,709	2,632	41,261	63,788
2011	NA	NA	3,259	236,931	13,753	2,687	41,781	64,309
2012	NA	NA	3,328	241,234	13,795	2,742	42,310	64,809
2013	NA	NA	3,400	245,834	13,830	2,799	42,867	65,304
2014	NA	NA	3,475	250,686	13,860	2,859	43,440	65,813
2015	NA	NA	3,549	255,444	13,892	2,916	43,934	66,372

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial			Railroads and Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Customers
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	GWh	GWh	GWh
1996	547	911	600,644	0	15	40	2,296
1997	566	944	599,349	0	17	41	2,698
1998	643	972	661,427	0	31	44	4,288
1999	678	1,031	657,495	0	31	45	4,385
2000	695	1,078	644,762	0	31	48	4,559
2001	692	1,104	626,720	0	35	49	4,630
2002	718	1,132	634,523	0	45	46	5,232
2003	708	1,151	615,521	0	57	46	6,594
2004	687	1,139	603,007	0	56	55	6,543
2005	732	1,169	626,396	0	58	45	6,762
2006	728	1,207	602,881	0	60	53	6,881
2007	741	1,242	596,818	0	61	53	7,034
2008	756	1,279	591,124	0	63	54	7,190
2009	771	1,317	585,702	0	64	55	7,388
2010	787	1,356	580,582	0	62	56	6,728
2011	804	1,396	575,556	0	63	58	6,870
2012	821	1,438	570,560	0	65	59	7,014
2013	839	1,483	565,511	0	67	60	7,164
2014	857	1,530	560,450	0	69	61	7,320
2015	876	1,577	555,624	0	71	62	7,474

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1996	0	110	2,405	0	91,851
1997	0	152	2,850	0	110,803
1998	0	242	4,530	0	170,022
1999	0	273	4,657	0	180,690
2000	0	278	4,838	0	184,476
2001	0	247	4,877	0	186,977
2002	0	301	5,532	0	207,904
2003	0	414	7,008	0	270,786
2004	0	457	7,000	0	275,690
2005	0	382	7,145	0	283,349
2006	0	436	7,317	0	287,799
2007	0	446	7,480	0	292,457
2008	0	456	7,646	0	297,242
2009	0	469	7,858	0	305,091
2010	0	429	7,157	0	275,380
2011	0	438	7,308	0	280,108
2012	0	447	7,461	0	284,983
2013	0	457	7,621	0	290,185
2014	0	467	7,787	0	295,656
2015	0	476	7,950	0	300,955

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
1996	503	0	0	0	0	0	0	0	503
1997	643	0	0	0	0	0	0	0	643
1998	947	0	0	0	0	0	0	0	947
1999	982	0	0	0	0	0	0	0	982
2000	972	0	0	0	0	0	0	0	972
2001	962	0	0	0	0	0	0	0	962
2002	992	0	0	0	0	0	0	0	992
2003	1,343	0	0	0	0	0	0	0	1,343
2004	1,416	0	0	0	0	0	0	0	1,416
2005	1,524	0	0	0	0	0	0	0	1,524
2006	1,467	0	0	0	0	0	0	0	1,467
2007	1,499	0	0	0	0	0	0	0	1,499
2008	1,533	0	0	0	0	0	0	0	1,533
2009	1,576	0	0	0	0	0	0	0	1,576
2010	1,435	0	0	0	0	0	0	0	1,435
2011	1,466	0	0	0	0	0	0	0	1,466
2012	1,497	0	0	0	0	0	0	0	1,497
2013	1,529	0	0	0	0	0	0	0	1,529
2014	1,562	0	0	0	0	0	0	0	1,562
2015	1,596	0	0	0	0	0	0	0	1,596

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
1995/96	564	0	0	0	0	0	0	0	564
1996/97	497	0	0	0	0	0	0	0	497
1997/98	675	0	0	0	0	0	0	0	675
1998/99	926	0	0	0	0	0	0	0	926
1999/00	947	0	0	0	0	0	0	0	947
2000/01	1,008	0	0	0	0	0	0	0	1,008
2001/02	1,008	0	0	0	0	0	0	0	1,008
2002/03	1,473	0	0	0	0	0	0	0	1,473
2003/04	1,194	0	0	0	0	0	0	0	1,194
2004/05	1,340	0	0	0	0	0	0	0	1,340
2005/06	1,427	0	0	0	0	0	0	0	1,427
2006/07	1,458	0	0	0	0	0	0	0	1,458
2007/08	1,490	0	0	0	0	0	0	0	1,490
2008/09	1,535	0	0	0	0	0	0	0	1,535
2009/10	1,365	0	0	0	0	0	0	0	1,365
2010/11	1,394	0	0	0	0	0	0	0	1,394
2011/12	1,423	0	0	0	0	0	0	0	1,423
2012/13	1,454	0	0	0	0	0	0	0	1,454
2013/14	1,486	0	0	0	0	0	0	0	1,486
2014/15	1,518	0	0	0	0	0	0	0	1,518

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1996	2,296	0	0	2,296	0	110	2,405	49%
1997	2,698	0	0	2,698	0	152	2,850	51%
1998	4,288	0	0	4,288	0	242	4,530	55%
1999	4,385	0	0	4,385	0	273	4,657	54%
2000	4,559	0	0	4,559	0	278	4,838	57%
2001	4,630	0	0	4,630	0	247	4,877	55%
2002	5,232	0	0	5,232	0	301	5,532	63%
2003	6,594	0	0	6,594	0	414	7,008	54%
2004	6,543	0	0	6,543	0	457	7,000	56%
2005	6,762	0	0	6,762	0	382	7,145	54%
2006	6,881	0	0	6,881	0	436	7,317	57%
2007	7,034	0	0	7,034	0	446	7,480	57%
2008	7,190	0	0	7,190	0	456	7,646	57%
2009	7,388	0	0	7,388	0	469	7,858	57%
2010	6,728	0	0	6,728	0	429	7,157	57%
2011	6,870	0	0	6,870	0	438	7,308	57%
2012	7,014	0	0	7,014	0	447	7,461	57%
2013	7,164	0	0	7,164	0	457	7,621	57%
2014	7,320	0	0	7,320	0	467	7,787	57%
2015	7,474	0	0	7,474	0	476	7,950	57%

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2006	1,526	0	0	0	0	0	0	0	1,526
2007	1,560	0	0	0	0	0	0	0	1,560
2008	1,594	0	0	0	0	0	0	0	1,594
2009	1,639	0	0	0	0	0	0	0	1,639
2010	1,492	0	0	0	0	0	0	0	1,492
2011	1,524	0	0	0	0	0	0	0	1,524
2012	1,556	0	0	0	0	0	0	0	1,556
2013	1,590	0	0	0	0	0	0	0	1,590
2014	1,625	0	0	0	0	0	0	0	1,625
2015	1,660	0	0	0	0	0	0	0	1,660

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Commercial/ Industrial Load Management	Commercial/ Industrial Load Conservation	Net Firm Demand
2005/06	1,485	0	0	0	0	0	0	0	1,485
2006/07	1,517	0	0	0	0	0	0	0	1,517
2007/08	1,550	0	0	0	0	0	0	0	1,550
2008/09	1,598	0	0	0	0	0	0	0	1,598
2009/10	1,420	0	0	0	0	0	0	0	1,420
2010/11	1,450	0	0	0	0	0	0	0	1,450
2011/12	1,480	0	0	0	0	0	0	0	1,480
2012/13	1,512	0	0	0	0	0	0	0	1,512
2013/14	1,545	0	0	0	0	0	0	0	1,545
2014/15	1,579	0	0	0	0	0	0	0	1,579

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2006	7,158	0	0	7,158	0	454	7,611	57%
2007	7,316	0	0	7,316	0	464	7,780	57%
2008	7,478	0	0	7,478	0	474	7,953	57%
2009	7,685	0	0	7,685	0	489	8,174	57%
2010	6,995	0	0	6,995	0	446	7,441	57%
2011	7,142	0	0	7,142	0	456	7,598	57%
2012	7,292	0	0	7,292	0	465	7,757	57%
2013	7,448	0	0	7,448	0	475	7,923	57%
2014	7,610	0	0	7,610	0	485	8,096	57%
2015	7,769	0	0	7,769	0	495	8,265	57%

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

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2006	1,413	0	0	0	0	0	0	0	1,413
2007	1,444	0	0	0	0	0	0	0	1,444
2008	1,476	0	0	0	0	0	0	0	1,476
2009	1,518	0	0	0	0	0	0	0	1,518
2010	1,383	0	0	0	0	0	0	0	1,383
2011	1,413	0	0	0	0	0	0	0	1,413
2012	1,443	0	0	0	0	0	0	0	1,443
2013	1,474	0	0	0	0	0	0	0	1,474
2014	1,506	0	0	0	0	0	0	0	1,506
2015	1,539	0	0	0	0	0	0	0	1,539

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

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Load Conservation	(10) Net Firm Demand
2005/06	1,375	0	0	0	0	0	0	0	1,375
2006/07	1,404	0	0	0	0	0	0	0	1,404
2007/08	1,436	0	0	0	0	0	0	0	1,436
2008/09	1,479	0	0	0	0	0	0	0	1,479
2009/10	1,316	0	0	0	0	0	0	0	1,316
2010/11	1,344	0	0	0	0	0	0	0	1,344
2011/12	1,372	0	0	0	0	0	0	0	1,372
2012/13	1,402	0	0	0	0	0	0	0	1,402
2013/14	1,433	0	0	0	0	0	0	0	1,433
2014/15	1,464	0	0	0	0	0	0	0	1,464

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Commercial/ Industrial Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2006	6,624	0	0	6,624	0	424	7,048	57%
2007	6,771	0	0	6,771	0	434	7,205	57%
2008	6,922	0	0	6,922	0	443	7,365	57%
2009	7,113	0	0	7,113	0	457	7,569	57%
2010	6,481	0	0	6,481	0	418	6,899	57%
2011	6,617	0	0	6,617	0	426	7,044	57%
2012	6,756	0	0	6,756	0	435	7,192	57%
2013	6,901	0	0	6,901	0	445	7,346	57%
2014	7,052	0	0	7,052	0	454	7,506	57%
2015	7,200	0	0	7,200	0	464	7,663	57%

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

Schedule 4
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2005		Forecast - 2006		Forecast - 2007	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	1,340	527	1,427	576	1,458	588
February	1,035	462	1,142	487	1,167	498
March	1,036	523	1,098	555	1,122	568
April	1,039	494	1,204	538	1,230	550
May	1,295	604	1,326	643	1,355	657
June	1,362	662	1,406	648	1,437	663
July	1,489	775	1,467	734	1,499	751
August	1,527	786	1,432	762	1,463	779
September	1,350	688	1,389	676	1,420	691
October	1,284	598	1,194	619	1,221	633
November	1,012	497	1,039	519	1,062	531
December	1,014	526	1,190	559	1,217	571

Florida Municipal Power Agency

Section 4.0

Conservation Programs

Community Power + Statewide Strength

4.0 Conservation Programs

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

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

- Energy Audits Program.
- High-Pressure Sodium Outdoor Lighting Conversion.
- Time-of-Use Program.
- Energy Star® Program Participation.
- Demand-Side Management.
- Distributed Generation.
- Green Energy Programs.

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

4.1 Energy Audits Program

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

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

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

As a supplement to the Energy Audits program, some FMPA members offer online energy surveys to their customers. These tools allow customers to enter specific information on their homes and review specific measures that they can implement in their homes to reduce energy consumption.

4.2 High-Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The mercury vapor fixtures are converted to high-pressure sodium fixtures whenever maintenance is required.

4.3 Time-of-Use Program

Time-of-use rates are being reviewed with the intention of shifting demand from peak to off-peak periods.

4.4 Energy Star®

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

4.5 Demand-Side Management

FMPA and its members are interested in demand-side initiatives that are of overall benefit to the ARP, but they are not currently pursuing the implementation of DSM programs at this time.

4.6 Distributed Generation

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

At this point in time, there is no active DG program. However, if there are significant advantages in DG technology or price, FMPA will review these possible benefits with members as needed.

The risks associated with DG include fuel storage, maintainability, permitting, and security. Control issues associated with DG include relinquishing customer control and having remote startup and shutdown monitoring. Cost issues associated with DG include high unit heat rates, high fuel costs, and redundant control equipment per location.

4.7 Green Energy Programs

FMPA and its members are reviewing Green Energy programs that may be a benefit to their customers. Renewable sources include solar thermal, solar photovoltaic, wind energy, and bioenergy. Although the electricity derived from the renewable energy source may not be directly provided to the customer, renewable energy is produced somewhere within the state or nation to offset electricity generated by fossil fuel sources.

Florida Municipal Power Agency

Section 5.0

Forecast of Facilities Requirements

Community Power + Statewide Strength

5.0 Forecast of Facilities Requirements

5.1 ARP Planning Process

FMPA's planning process involves evaluating new generating capacity, along with new purchased power options, if appropriate, and conservation measures that are planned and implemented by the All-Requirements Project participants. The planning process has also included periodic requests for proposals in an effort to consider all possible options. FMPA normally performs its generation expansion planning on a least-cost basis considering both purchased-power options, as well as options on construction of generating capacity and demand-side resources when cost effective. The generation expansion plan optimizes the planned mix of possible supply-side resources by simulating their dispatch for each year of the study period while considering variables including fixed and variable resource costs, fuel costs, planned maintenance outages, terms of purchase contracts, minimum reserve requirements, and options for future resources. FMPA currently plans for an annual reserve level of approximately 18 percent of the summer peak. FMPA is continually reviewing its options, seeking joint participation when feasible, and may change the megawatts required, the year of installment, the type of generation, and/or the site at which generation is planned to be added as conditions change.

5.2 Planned ARP Generating Facility Requirements

FMPA is planning to add a 42 MW combustion turbine at Stock Island in June 2006, a 296 MW combined cycle unit at the Treasure Coast Energy Center site in June 2008, 84 MW of combustion turbine capacity in 2010, a 288 MW share of a jointly owned coal-fired unit in June 2012, and an additional 296 MW combined cycle unit in 2014.

FMPA is currently participating with three other municipal utilities in the development of the Taylor Energy Center, a 750 MW coal-fired project located in north Florida. The primary advantage of a publicly-owned, coal-fired project would be to diversify resources, while supplying competitively priced power into the future. The group is actively performing engineering, siting, environmental, and transmission line studies related to the project. Additionally, generation can be added at the Cane Island Power Park, at Lake Worth Utilities, and at Keys Energy Services' Stock Island Plant. Further, reciprocating engines or small combustion turbine generation can be installed on any ARP member system.

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

5.3 Capacity and Purchase Power Requirements

The current system firm power supply purchase resources of ARP include purchases from PEF, FPL, OUC, Lakeland Electric, GRU, Calpine, and the Southern Company-Florida Stanton A capacity that is purchased power. Additionally, FMPA is planning a peaking power purchase from Southern Company's Oleander plant beginning in December 2007 and a capacity purchase from an unknown utility or utilities for the summers of 2007, 2011, and 2013. The existing and future power purchase contracts are briefly summarized below:

- **PEF:** FMPA has a power contract with PEF for Partial Requirements (PR) Services. FMPA expects to take 40 MW in 2006, 30 MW in 2007 and 2008, 60 MW in 2009, and 40 MW in 2010. The PR capacity also includes reserves.
- **FPL:** FMPA has two contracts with FPL, including a short-term 75 MW purchase through 2007 and a long-term 45 MW purchase until June 2013. The FPL short and long-term purchases include reserves.
- **OUC:** FMPA has a 22 MW purchase in 2006 from the OUC Indian River plant, which purchase expires thereafter.
- **Lakeland Electric:** FMPA has a 100 MW contract with Lakeland Electric. This contract originally extended through 2010, but it has been renegotiated so that the capacity will be replaced with FMPA resources in December 2007.
- **GRU:** FMPA has a 3 MW contract with GRU through 2006.
- **Calpine:** FMPA has a contract with Calpine that provides 75 MW in 2006. The amount increases to 100 MW in 2007 until the contract expires in 2009.
- **Southern Company-Florida:** FMPA has a contract for 82 MW of purchase power including KUA's share from Stanton A that extends to 2013 for the initial term and has various extension options.
- **Southern Company:** FMPA is planning to purchase 157 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. The purchase will have a term of 20 years.

- **Peaking Purchase:** To satisfy its planning reserve requirements, FMPA intends to purchase 25 MW, 62 MW, and 42 MW of peaking capacity during the summers of 2007, 2011, and 2013, respectively, from one or more unknown utilities.

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.

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

Line No.	Resource Description	Summer Rating (MW)									
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	84	83	83	83	72	72	72	72	72	72
2	Stanton Coal Plant	224	224	224	224	186	186	186	186	186	186
3	Stanton CC Unit A	42	42	42	42	42	42	42	42	42	42
4	Cane Island 1-3	388	388	388	388	388	388	388	388	388	388
5	Indian River CTs	82	82	82	82	82	82	82	82	82	82
6	Key West Units 2&3	31	31	31	31	31	31	31	31	31	31
7	Ft. Pierce Native Generation	110	110	-	-	-	-	-	-	-	-
8	Key West Native Generation	41	41	41	41	41	41	41	41	41	41
9	Kissimmee Native Generation	48	48	48	48	48	48	-	-	-	-
10	Lake Worth Native Generation	87	87	87	87	87	87	-	-	-	-
11	Vero Beach Native Generation	137	137	137	137	-	-	-	-	-	-
12	Sub Total Existing Resources	1,271	1,271	1,161	1,161	975	975	841	841	841	841
	Planned Additions										
13	Stock Island Unit 4	42	42	42	42	42	42	42	42	42	42
14	Treasure Coast Energy Center	-	-	296	296	296	296	296	296	296	296
15	Taylor Energy Center	-	-	-	-	-	-	288	288	288	288
16	New Peaking Capacity	-	-	-	-	84	84	84	84	84	84
17	New Base/Intermediate Capacity	-	-	-	-	-	-	-	-	296	296
18	Sub Total Planned Additions	42	42	338	338	422	422	710	710	1,006	1,006
19	**Total Installed Capacity**	**1,313**	**1,313**	**1,499**	**1,499**	**1,397**	**1,397**	**1,552**	**1,552**	**1,848**	**1,848**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
20	OUC Indian River Purchase	22	-	-	-	-	-	-	-	-	-
21	Starke (GRU)	3	-	-	-	-	-	-	-	-	-
22	Lakeland Purchase	100	100	-	-	-	-	-	-	-	-
23	Calpine Purchase	75	100	100	100	-	-	-	-	-	-
24	Stanton A Purchase	80	80	80	80	80	80	80	80	-	-
25	Peaking Purchase	-	25	-	-	-	62	-	42	-	-
26	Southern Company Purchase	-	-	157	157	157	157	157	157	157	157
27	Sub Total Without Reserves	279	305	337	337	237	299	237	279	157	157
	Firm Capacity Import With Reserves										
28	PEF Partial Requirements	40	30	30	60	40	-	-	-	-	-
29	FPL Partial Requirements	45	45	45	45	45	45	45	-	-	-
30	FPL Long-Term Partial Requirements	75	75	-	-	-	-	-	-	-	-
31	Sub Total With Reserves	160	150	75	105	85	45	45	-	-	-
32	**Total Firm Capacity Import**	**439**	**455**	**412**	**442**	**322**	**344**	**282**	**279**	**157**	**157**
33	**Total Available Capacity**	**1,753**	**1,767**	**1,910**	**1,940**	**1,719**	**1,741**	**1,833**	**1,830**	**2,005**	**2,005**

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

Line No.	Resource Description	Winter Rating (MW)									
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear)	86	85	85	85	73	74	74	74	74	74
2	Stanton Coal Plant	224	224	224	224	187	187	187	187	187	187
3	Stanton CC Unit A	46	46	46	46	46	46	46	46	46	46
4	Cane Island 1-3	400	400	400	400	400	400	400	400	400	400
5	Indian River CTs	99	99	99	99	99	99	99	99	99	99
6	Key West Units 2&3	36	36	36	36	36	36	36	36	36	36
7	Ft. Pierce Native Generation	118	118	118	-	-	-	-	-	-	-
8	Key West Native Generation	50	43	43	43	43	43	43	43	43	43
9	Kissimmee Native Generation	45	45	45	45	45	45	-	-	-	-
10	Lake Worth Native Generation	97	97	97	97	97	97	97	-	-	-
11	Vero Beach Native Generation	155	155	155	155	-	-	-	-	-	-
12	Sub Total Existing Resources	1,357	1,349	1,349	1,231	1,027	1,027	982	885	885	885
	Planned Additions										
13	Stock Island Unit 4	-	42	42	42	42	42	42	42	42	42
14	Treasure Coast Energy Center	-	-	-	318	318	318	318	318	318	318
15	Taylor Energy Center	-	-	-	-	-	-	-	288	288	288
16	New Peaking Capacity	-	-	-	-	-	97	97	97	97	97
17	New Base/Intermediate Capacity	-	-	-	-	-	-	-	-	-	318
18	Sub Total Planned Additions	-	42	42	360	360	457	457	745	745	1,063
19	**Total Installed Capacity**	**1,357**	**1,391**	**1,391**	**1,591**	**1,387**	**1,484**	**1,439**	**1,631**	**1,631**	**1,949**
	Firm Capacity Import										
	Firm Capacity Import Without Reserves										
20	OUC Indian River Purchase	22	-	-	-	-	-	-	-	-	-
21	Starke (GRU)	3	-	-	-	-	-	-	-	-	-
22	Lakeland Purchase	100	100	-	-	-	-	-	-	-	-
23	Calpine Purchase	75	100	100	100	-	-	-	-	-	-
24	Stanton A Purchase	86	86	86	86	86	86	86	86	-	-
25	Peaking Purchase	-	-	-	-	-	-	-	-	-	-
26	Southern Company Purchase	-	-	157	157	157	157	157	157	157	157
27	Sub Total Without Reserves	285	286	343	343	243	243	243	243	157	157
	Firm Capacity Import With Reserves										
28	PEF Partial Requirements	40	30	30	60	40	-	-	-	-	-
29	FPL Partial Requirements	45	45	45	45	45	45	45	45	-	-
30	FPL Long-Term Partial Requirements	75	75	-	-	-	-	-	-	-	-
31	Sub Total With Reserves	160	150	75	105	85	45	45	45	-	-
32	**Total Firm Capacity Import**	**445**	**436**	**418**	**448**	**328**	**288**	**288**	**288**	**157**	**157**
33	**Total Available Capacity**	**1,802**	**1,827**	**1,809**	**2,039**	**1,715**	**1,772**	**1,727**	**1,918**	**1,788**	**2,106**

Schedule 5
Fuel Requirements – All-Requirements Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Fuel Type	Unit Type	Fuel Units	Actual 2005	Forecasted 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	Nuclear [1]		Trillion BTU	7	7	7	7	7	6	6	6	6	6	6
2	Coal		000 Ton	586	658	664	667	662	542	517	937	1,244	1,253	1,248
	Residual													
3		Steam	000 BBL	-	13	22	6	2	-	-	-	-	-	-
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL	-	13	22	6	2	-	-	-	-	-	-
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	18	14	11	12	10	20	25	26	27	20
9		CT	000 BBL	48	53	77	76	84	91	100	107	125	129	144
10		Total	000 BBL	48	71	91	87	96	101	119	132	150	156	164
	Natural Gas													
11		Steam	000 MCF	440	6	8	3	59	9	7	-	-	-	-
12		CC	000 MCF	15,135	18,051	19,088	26,914	31,283	31,186	25,586	23,619	22,521	25,904	29,167
13		CT	000 MCF	108	788	959	887	884	1,302	930	536	758	447	675
14		Total	000 MCF	15,683	18,844	20,055	27,804	32,226	32,497	26,523	24,155	23,279	26,351	29,842
15	Other		Trillion BTU	-	0	0	0	0	0	0	0	0	0	0

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

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

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	628	648	651	649	653	545	580	566	562	562	563
3	Coal		GWh	1,496	1,650	1,655	1,665	1,653	1,356	1,303	2,403	3,285	3,310	3,306
	Residual													
4		Steam	GWh	-	5	9	2	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	5	9	2	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	27	28	42	42	47	51	57	61	70	74	81
11		Total	GWh	27	28	42	42	47	51	57	61	70	74	81
	Natural Gas													
12		Steam	GWh	27	-	-	-	4	0	0	-	-	-	-
13		CC	GWh	2,014	2,392	2,521	3,601	4,178	4,185	3,391	3,144	3,003	3,445	3,865
14		CT	GWh	10	71	87	80	80	123	89	51	73	42	64
15		Total	GWh	2,051	2,463	2,608	3,681	4,261	4,309	3,480	3,196	3,076	3,487	3,929
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		GWh	-	-	-	-	-	-	-	-	-	-	-
18	Interchange		GWh	2,940	2,656	2,650	1,741	1,335	975	1,970	1,316	708	436	154
19	Net Energy for Load		GWh	7,142	7,450	7,615	7,781	7,950	7,236	7,388	7,542	7,701	7,869	8,033

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

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	9	9	9	8	8	8	8	8	7	7	7
3	Coal		%	21	22	22	21	21	19	18	32	43	42	41
	Residual													
4		Steam	%	-	0	0	0	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	0	0	0	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0	0	1	1	1	1	1	1	1	1	1
11		Total	%	0	0	1	1	1	1	1	1	1	1	1
	Natural Gas													
12		Steam	%	0	-	-	-	0	0	0	-	-	-	-
13		CC	%	28	32	33	46	53	58	46	42	39	44	48
14		CT	%	0	1	1	1	1	2	1	1	1	1	1
15		Total	%	29	33	34	47	54	60	47	42	40	44	49
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
17	Hydro		%	-	-	-	-	-	-	-	-	-	-	-
18	Interchange		%	41	36	35	22	17	13	27	17	9	6	2
19	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	System Firm Summer Peak Demand	Reserve Margin before Maintenance [3]		Scheduled Maintenance	Reserve Margin after Maintenance [3]	
Year	(MW) [1]	(MW)	(MW)	QF (MW)	(MW)	(MW) [2]	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2006	1,313	439	0	0	1,753	1,484	269	20%	0	269	20%
2007	1,313	455	0	0	1,767	1,516	251	18%	0	251	18%
2008	1,499	412	0	0	1,910	1,550	360	24%	0	360	24%
2009	1,499	442	0	0	1,940	1,594	347	23%	0	347	23%
2010	1,397	322	0	0	1,719	1,449	270	20%	0	270	20%
2011	1,397	344	0	0	1,741	1,480	261	18%	0	261	18%
2012	1,552	282	0	0	1,833	1,511	322	22%	0	322	22%
2013	1,552	279	0	0	1,830	1,544	287	19%	0	287	19%
2014	1,848	157	0	0	2,005	1,579	426	27%	0	426	27%
2015	1,848	157	0	0	2,005	1,613	392	24%	0	392	24%

[1] See Table 1-6 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Summer Peak Demand includes transmission losses for the members served through FPL.

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

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW) [1]	Firm Capacity Import (MW) [1]	Firm Capacity Export (MW)	QF (MW)	Total Available Capacity (MW)	System Firm Winter Peak Demand (MW) [2]	Reserve Margin before Maintenance [3] (MW)	Reserve Margin before Maintenance [3] (% of Peak)	Scheduled Maintenance (MW)	Reserve Margin after Maintenance [3] (MW)	Reserve Margin after Maintenance [3] (% of Peak)
2005/06	1,357	445	0	0	1,802	1,444	358	28%	0	358	28%
2006/07	1,391	436	0	0	1,827	1,475	352	27%	0	352	27%
2007/08	1,391	418	0	0	1,809	1,508	301	21%	0	301	21%
2008/09	1,591	448	0	0	2,039	1,554	485	33%	0	485	33%
2009/10	1,387	328	0	0	1,715	1,379	336	26%	0	336	26%
2010/11	1,484	288	0	0	1,772	1,408	364	27%	0	364	27%
2011/12	1,439	288	0	0	1,727	1,438	289	21%	0	289	21%
2012/13	1,631	288	0	0	1,918	1,468	450	32%	0	450	32%
2013/14	1,631	157	0	0	1,788	1,501	287	19%	0	287	19%
2014/15	1,949	157	0	0	2,106	1,534	571	37%	0	571	37%

[1] See Table 1-7 for a listing of the resources identified as Installed Capacity and Firm Capacity Import.

[2] System Firm Winter Peak Demand includes transmission losses for the members served through FPL.

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

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability		Status
				Primary	Alt.	Primary	Alt.					Summer MW	Winter MW	
Resource Additions														
Stock Island	CT4	Monroe	GT	DFO	-	TK	-	NA	06/06	NA	NA	42	42	U
Treasure Coast Energy Center	Unit 1	St. Lucie	CC	NG	DFO	PL	TK	NA	06/08	NA	NA	296	318	L
Unsited Combustion Turbine	CT1	Unknown	GT	NG	DFO	PL	TK	NA	06/10	NA	NA	42	49	P
Unsited Combustion Turbine	CT2	Unknown	GT	NG	DFO	PL	TK	NA	06/10	NA	NA	42	49	P
Taylor Energy Center	Unit 1	Taylor	ST	BIT	-	RR	-	NA	06/12	NA	NA	288	288	P
Unsited Combined Cycle	CC	Unknown	CC	NG	DFO	PL	-	NA	06/14	NA	NA	296	318	P
Changes to Existing Resources														
Big Pine Key	1	Monroe	IC	DFO	-	TK	-	NA	02/69	02/06	3	(3)	(3)	RT
Cudjoe Key Peaker	2	Monroe	IC	DFO	-	TK	-	NA	08/68	02/06	3	(3)	(3)	RT
Cudjoe Key Peaker	3	Monroe	IC	DFO	-	TK	-	NA	08/68	02/06	2	(2)	(2)	RT
H.D. King	5	St. Lucie	CA	WH	-	-	-	NA	01/53	05/08	8	(8)	(8)	RT
H.D. King	7	St. Lucie	ST	NG	RFO	PL	TK	NA	01/64	05/08	32	(32)	(32)	RT
H.D. King	8	St. Lucie	ST	NG	RFO	PL	TK	NA	05/76	05/08	50	(50)	(50)	RT
H.D. King	9	St. Lucie	CT	NG	DFO	PL	TK	NA	05/90	05/08	23	(23)	(23)	RT
H.D. King	D1	St. Lucie	IC	DFO	-	TK	-	NA	04/70	05/08	3	(3)	(3)	RT
H.D. King	D2	St. Lucie	IC	DFO	-	TK	-	NA	04/70	05/08	3	(3)	(3)	RT
Hansel Plant	21	Osceola	CT	NG	DFO	PL	TK	NA	02/83	12/11	38	(30)	(38)	RT
Hansel Plant	22	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(6)	RT
Hansel Plant	23	Osceola	CA	WH	-	-	-	NA	11/83	12/11	8	(8)	(6)	RT
Tom G. Smith	GT-1	Palm Beach	GT	DFO	-	TK	-	NA	12/76	06/12	31	(26)	(31)	RT
Tom G. Smith	GT-2	Palm Beach	CT	NG	DFO	PL	TK	NA	03/78	06/12	20	(21)	(23)	RT
Tom G. Smith	MU1	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)	RT
Tom G. Smith	MU2	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)	RT
Tom G. Smith	MU3	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)	RT
Tom G. Smith	MU4	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)	RT
Tom G. Smith	MU5	Palm Beach	IC	DFO	-	TK	-	NA	12/65	06/12	2	(2)	(2)	RT
Tom G. Smith	S-3	Palm Beach	ST	NG	RFO	PL	TK	NA	11/67	06/12	27	(22)	(24)	RT
Tom G. Smith	S-5	Palm Beach	CA	WH	-	-	-	NA	03/78	06/12	10	(9)	(9)	RT

Florida Municipal Power Agency

Section 6.0

Site and Facility Descriptions

Community Power + Statewide Strength

6.0 Site and Facility Descriptions

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

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

FMPA anticipates that the LM6000 simple cycle combustion turbines could be installed at an ARP member owned generation site, most likely at either the Tom G. Smith Power Plant site at Lake Worth or the Cane Island Power Park site at KUA, or at FMPA's Treasure Coast Energy Center site. FMPA anticipates that combined cycle generation could be installed at an existing ARP site, either at Cane Island or at the Treasure Coast Energy Center. Additional coal generation could be located at the Taylor Energy Center site or in joint ownership at another utility's site.

Stock Island

FMPA is installing a 42 MW aeroderivative, combustion turbine (CT) unit, Stock Island CT Unit 4, at the Keys Energy Services' Stock Island Plant in Monroe County. The new CT and all auxiliary equipment have been placed on their foundations at the site and are currently in the process of interconnection. The operational date is set at June 28, 2006.

The Stock Island site currently consists of five diesel generating units, as well as three combustion turbines. The site receives water from the Florida Keys Aqueduct Authority via a pipeline from the mainland, and also uses on-site groundwater. The site receives delivery of fuel oil to its unloading system through waterborne delivery, and also has the capability of receiving fuel oil deliveries via truck. The site has no adverse impact on surrounding wetlands, threatened or endangered animal species, or any designated natural resources.

Treasure Coast Energy Center

FMPA is planning to construct a new 296 MW, 1x1 7FA combined cycle facility at the Treasure Coast Energy Center site. The information related to this unit contained herein is consistent with the contents of FMPA's TCEC Unit 1 Need for Power Application filed in April 2005. The Treasure Coast Energy Center will be located in St. Lucie County near the City of Fort Pierce. All public hearings have been held for the site certification with no major issues. The site is being certified to accommodate construction of future units beyond TCEC Unit 1, up to a total of 1,200 MW. Certification is anticipated in May 2006. Commercial operation of TCEC Unit 1 is scheduled for May 2008.

Cane Island Power Park

Cane Island Power Park is located south and west of KUA's service area and contains 380 MW (summer) of gas turbine and combined cycle capacity. The Cane Island Power Park consists of a simple cycle gas turbine and two combined cycle generating units, each of which is 50 percent owned by FMPA and 50 percent owned by KUA

Taylor Energy Center

FMPA is currently participating with three other municipal utilities in the development of a jointly-owned coal plant at a site in Taylor County, Florida. FMPA has received alternative power supply proposals which are currently being evaluated. Decisions are forthcoming on accepting the alternative proposals, submitting the request for "need for power", and settling land purchase contracts.

The Taylor Energy Center (TEC) site is approximately 3,300 acres, located just south of Perry in north Florida. Please refer to the TEC Web site at www.taylorenergycenter.org for additional information.

Tom G. Smith Power Plant (Lake Worth)

The Tom G. Smith Power Plant is located in the City of Lake Worth's service area in Palm Beach County and currently consists of 88 MW of steam, combined cycle, and reciprocating engine generation. The site is suitable for possible future repowering or addition of new combustion turbines or combined cycle capacity.

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

(1)	Plant Name and Unit Number	Stock Island CT4
(2)	Capacity	
	a. Summer	42
	b. Winter	42
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	Jul-04
	b. Commercial In-Service Date	Jun-06
(5)	Fuel	
	a. Primary Fuel	No. 2 Oil
	b. Alternate Fuel	NA
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Less than 10 Acres
(9)	Construction Status	Under construction, less than or equal to 50% complete
(10)	Certification Status	Approved
(11)	Status with Federal Agencies	Approved
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor	95.1%
	Resulting Capacity Factor	19.7%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$779
	Direct Construction Cost (2005 $/kW)	$680
	AFUDC Amount ($/kW) [1]	$80
	Escalation ($/kW)	$19
	Fixed O&M ($/kW)	13.87 $/kW-yr
	Variable O&M ($/MWh)	$3.00

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Treasure Coast Energy Center Unit 1
(2)	Capacity	
	a. Summer	296
	b. Winter	318
(3)	Technology Type	CC (1x1 GE 7FA)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2006
	b. Commercial In-Service Date	Jun-08
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	69 Acres
(9)	Construction Status	Regulatory Approval Pending. Not Under Construction
(10)	Certification Status	Final Approval Pending
(11)	Status with Federal Agencies	Approved
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5.8%
	Forced Outage Factor (FOF)	6.3%
	Equivalent Availability Factor	88.3%
	Resulting Capacity Factor	50.0%
	Average Net Operating Heat Rate (ANOHR)	7,527 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$899
	Direct Construction Cost (2005 $/kW)	$747
	AFUDC Amount ($/kW) [1]	$88
	Escalation ($/kW)	$64
	Fixed O&M ($/kW)	6.27 $/kW-yr
	Variable O&M ($/MWh)	$2.74

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Unsited Combustion Turbine Unit 1
(2)	Capacity	
	a. Summer	42
	b. Winter	48.5
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2008
	b. Commercial In-Service Date	Jun-10
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor	95.1%
	Resulting Capacity Factor	4.6%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$859
	Direct Construction Cost (2005 $/kW)	$680
	AFUDC Amount ($/kW) [1]	$80
	Escalation ($/kW)	$100
	Fixed O&M ($/kW)	13.87 $/kW-yr
	Variable O&M ($/MWh)	$3.00

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Unsited Combustion Turbine Unit 2
(2)	Capacity	
	a. Summer	42
	b. Winter	48.5
(3)	Technology Type	GT (General Electric LM6000 PC-SPRINT)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2008
	b. Commercial In-Service Date	Jun-10
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Water Injection
(7)	Cooling Method	Air
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	1.9%
	Forced Outage Factor (FOF)	3.0%
	Equivalent Availability Factor	95.1%
	Resulting Capacity Factor	4.1%
	Average Net Operating Heat Rate (ANOHR)	10,136 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$859
	Direct Construction Cost (2005 $/kW)	$680
	AFUDC Amount ($/kW) [1]	$80
	Escalation ($/kW)	$100
	Fixed O&M ($/kW)	13.87 $/kW-yr
	Variable O&M ($/MWh)	$3.00

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Taylor Energy Center Unit 1
(2)	Capacity	
	a. Summer	288
	b. Winter	288
(3)	Technology Type	ST (Supercritical Pulverized Coal)
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2008
	b. Commercial In-Service Date	Jun-12
(5)	Fuel	
	a. Primary Fuel	Bituminous Coal
	b. Alternate Fuel	NA
(6)	Air Pollution Control Strategy	Engineering Review in Progress
(7)	Cooling Method	Engineering Reivew in Progress
(8)	Total Site Area	3,300 Acres
(9)	Construction Status	Planned
(10)	Certification Status	FPSC Need Filing Expected Spring/Summer 2006
(11)	Status with Federal Agencies	Preliminary Review
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	NA
	Forced Outage Factor (FOF)	NA
	Equivalent Availability Factor	NA
	Resulting Capacity Factor	NA
	Average Net Operating Heat Rate (ANOHR)	NA
(13)	Projected Unit Financial Data	
	Book Life (Years)	NA
	Total Installed Cost (In-Service Year $/kW)	NA
	Direct Construction Cost (2005 $/kW)	NA
	AFUDC Amount ($/kW) [1]	NA
	Escalation ($/kW)	NA
	Fixed O&M ($/kW)	NA
	Variable O&M ($/MWh)	NA

[1] Includes AFUDC and bond issuance expenses

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

(1)	Plant Name and Unit Number	Combined Cycle Unit 1
(2)	Capacity	
	a. Summer	296
	b. Winter	318
(3)	Technology Type	CC
(4)	Anticipated Construction Timing	
	a. Field Construction Start Date	2012
	b. Commercial In-Service Date	Jun-14
(5)	Fuel	
	a. Primary Fuel	Natural Gas
	b. Alternate Fuel	No. 2 Oil
(6)	Air Pollution Control Strategy	Low NO2 Combustors, Water Injection
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	Unknown
(9)	Construction Status	Planned
(10)	Certification Status	Existing Site
(11)	Status with Federal Agencies	Existing Site
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5.8%
	Forced Outage Factor (FOF)	6.3%
	Equivalent Availability Factor	88.3%
	Resulting Capacity Factor	49.7%
	Average Net Operating Heat Rate (ANOHR)	7,476 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	$1,043
	Direct Construction Cost (2005 $/kW)	$747
	AFUDC Amount ($/kW) [1]	$88
	Escalation ($/kW)	$208
	Fixed O&M ($/kW)	6.27 $/kW-yr
	Variable O&M ($/MWh)	$2.74

[1] Includes AFUDC and bond issuance expenses

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

(1)	Point of Origin and Termination	TCEC (FMPA) to Ralls (FPL) [1]
(2)	Number of Lines	One
(3)	Right-of-Way	New Transmission Right-of-Way
(4)	Line Length	500 feet
(5)	Voltage	230 kV
(6)	Anticipated Construction Timing	February 2007
(7)	Anticipated Capital Investment	$12,484,000 [2]
(8)	Substations	TCEC
(9)	Participation with Other Utilities	FPL

Notes:
[1] New FPL substation
[2] Planned network upgrades

Florida Municipal Power Agency

Appendix I

List of Abbreviations

Community Power + Statewide Strength

Appendix I
List of Abbreviations

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
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.

Other

NA	Not Available or Not Applicable

Florida Municipal Power Agency

Appendix II

Other Member Transmission Information

Community Power + Statewide Strength

Appendix II
Other Member Transmission Information

Appendix II
Other Member Transmission Information

Table II-1 presented on the following pages contains a list of planned and proposed transmission line additions for member cities of the Florida Municipal Power Agency who participate in the All-Requirements Project, as well as other (non-ARP) member cities that are not required to file a Ten-Year Site Plan.

Table II-1
Planned and Proposed Transmission Additions for FMPA Members
2006 through 2015 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
FMPA	TCEC (FMPA)	Ralls (FPL)	759	230 kV	1	9/2007
	TCEC Substation			230 kV		9/2007
Ft. Pierce	Hartman Auto-Xfmr1Upgrade		100	138/69 kV	1	9/2007
	Hartman Auto-Xfmr2 Upgrade		100	138/69 kV	2	9/2007
	FPL-TCEC Switchyard	Southwest Sub	200	230 kV	1	9/2011
	Southwest Sub Auto-Xfmr Addition		167	230/138 kV	1	9/2011
	Southwest Sub	Hartman Sub	200	138 kV	1	9/2015
Homestead	Redland	Lucy		138 kV	1	12/2006
	Renaissance	Lucy		138 kV	1	12/2006
	Redland Substation			138 kV		12/2006
	Renaissance Substation			138 kV		12/2006
Jacksonville Beach	Jacksonville Beach (Reconductor)	Neptune		138 kV	1	6/2011
Key West & FKEC	Tavernier	Islamorada		138 kV	2	6/2015
	Islamorada	Marathon		138 kV	2	6/2015
	Florida City	Tavernier		138 kV	2	6/2015
	Tavernier			ring bus		6/2015
	KWD Transformer			69/13.8kV		6/2008
	SIS 4th Ave Transformer			69/13.8kV		6/2008
Kissimmee	Hansel (Reconductor)	C.A.Wall		69 kV	1	6/2007
	C.A.Wall	Turnpike		69 kV	1	6/2007
	Pleasant Hill Substation	Hansel		69 kV	1	5/2007
	Pleasant Hill Substation	Clay Street		69 kV	1	5/2007
	Neptune Road Substation	Tie Point with St.Cloud		69 kV	1	6/2009
	Clay Auto-Txfmr		200	230/69 kV	2	6/2010
	Lake Bryan	Osceola		69 kV	1	6/2012
	Lake Cecile	Osceola		69 kV	1	6/2012
	Neptune Road Substation	Tie Point with St.Cloud		69 kV	1	6/2010

Table II-1 (Continued)
Planned and Proposed Transmission Additions for FMPA Members
2006 through 2015 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Lake Worth	Canal Transformer		60	138/26 kV	2	12/2007
	Hypoluxo	Canal		138 kV	1	12/2008
New Smyrna Beach	30 MVA Txfmr (Field Street Substation)		30	115/23 kV	1	11/2006
	30 MVA Txfmr		30	115/23 kV		1/2009
	30 MVA Txfmr		30	115/23 kV		1/2011
	30 MVA Txfmr		30	115/23 kV		1/2014
	115 kV Loop Field St - Airport			115 kV	1	1/2014
Ocala	Shaw	Silver Springs North		230 kV	1	12/2006
	Ergle	Silver Springs North		230 kV	2	12/2006
	Shaw Auto-Txfmr		150	230/69 kV	2	10/2006
	Nuby's Corner Substation			69 kV		6/2006
	Nuby's Corner	Silver Springs		69 kV	1	6/2006
	Nuby's Corner	Baseline Rd		69 kV	1	7/2007
	Ocala Springs Substation			69 kV		6/2008
	Ocala Springs	Ergle		69 kV	1	6/2008
	Ocala Springs	Silver Springs		69 kV	1	6/2008
	Dearmin	Baseline Rd		69 kV	1	6/2009
	Dearmin / Baseline Substation (Improvements)			69 kV		6/2009
	Fore Corners Substation			69 kV		6/2011
	Fore Corners	Ergle		69 kV	1	6/2011
	Fore Corners	Ocala North		69 kV	1	6/2017
	Shaw	Silver Springs		230 kV	1	6/2012
Vero Beach	Sub #6	Sub #1		69 kV	1	6/2007

Florida Municipal Power Agency

Appendix III

Additional Reserve Margin Information

Community Power + Statewide Strength

Appendix III
Additional Reserve Margin Information

Appendix III
Additional Reserve Margin Information

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

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

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2006	1,753	1,484	160	269	20%
2007	1,767	1,516	150	251	18%
2008	1,910	1,550	75	360	24%
2009	1,940	1,594	105	347	23%
2010	1,719	1,449	85	270	20%
2011	1,741	1,480	45	261	18%
2012	1,833	1,511	45	322	22%
2013	1,830	1,544	0	287	19%
2014	2,005	1,579	0	426	27%
2015	2,005	1,613	0	392	24%

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

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

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

Year	Total Available Capacity (MW)	System Firm Peak Demand (MW)	Partial Requirements Purchases (MW)	Reserve Margin (MW) [1]	Reserve Margin (%) [2]
(a)	(b)	(c)	(d)	(e)	(f)
2005/06	1,802	1,444	160	358	28%
2006/07	1,827	1,475	150	352	27%
2007/08	1,809	1,508	75	301	21%
2008/09	2,039	1,554	105	485	33%
2009/10	1,715	1,379	85	336	26%
2010/11	1,772	1,408	45	364	27%
2011/12	1,727	1,438	45	289	21%
2012/13	1,918	1,468	45	450	32%
2013/14	1,788	1,501	0	287	19%
2014/15	2,106	1,534	0	571	37%

[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

Appendix IV

Supplemental Information

Community Power + Statewide Strength

Appendix IV
Supplemental Information

Appendix IV
Supplemental Information

This appendix presents information typically requested by and provided to the PSC in a supplemental filing.

Q1. **Provide all data requested on the attached forms. If any of the requested data is already included in FMPA's Ten-Year Site Plan, state so on the appropriate form.**

See Tables IV-1 through IV-7.

Q2. **Illustrate what FMPA's generation expansion plan would be as a result of sensitivities to the base case demand and fuel price forecast. Include the cumulative present worth revenue requirements of each sensitivity case.**

FMPA's Base Case generation expansion plan was held constant for the various sensitivities to the fuel price forecast. FMPA did not perform sensitivities to the Base Case demand forecast. Some adjustments to the timing of certain planned resources could be made in the event that a material change in demand was to occur in the future.

In addition to the Base Case, FMPA has performed High and Low Fuel Price Sensitivities, as well as an additional sensitivity that held the price differential between gas and coal constant over the study period (the "Fixed Fuel" case).

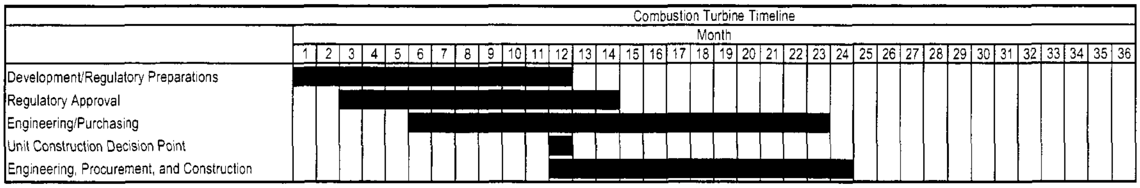
The cumulative present worth revenue requirements (CPWRR) over the period 2006-2035 for the Base Case were approximately $12.6 billion. The CPWRR for the High and Low Fuel Price Sensitivities were approximately $16.6 billion and $9.9 billion, respectively. The CPWRR for the Fixed Fuel case was approximately $12.3 billion.

Q3. **Describe the nature of FMPA's options to continue purchasing capacity under its existing contracts.**

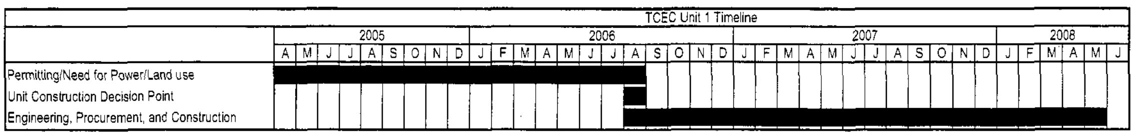
FMPA has options in several power agreements to purchase additional power if required.

Q4. **For each of the generating units contained in FMPA's Ten-Year Site Plan, discuss the "drop-dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.**

Combustion Turbine: A typical combustion turbine timeline is shown below:



Combined Cycle: The planned timeline for construction of TCEC Unit 1, which may also be viewed as a representative example of the timeline for the planned 2014 combined cycle unit, is shown below:



Coal: Design and permitting for the Taylor Energy Center is scheduled to begin in 2006. Construction is scheduled to commence during 2008. Commercial operation is planned for summer 2012.

Q5. **Discuss the earliest possible date that FMPA could acquire certification for, and place into commercial operation, a pulverized coal or coal gasification combined cycle unit.**

A group of public utilities have joined together to participate in the development of the Taylor Energy Center, a 750 MW coal-fired project to be located in Taylor County in north Florida. The primary advantage of a publicly-owned, coal-fired project would be to diversify resources, while supplying competitively priced power into the future. The group is actively performing engineering, siting, environmental, and transmission line studies related to the project. As of December 31, 2005, the anticipated in-service date for the Taylor Energy Center is June 2012.

Q6. **Provide, on a system-wide basis, historical annual heating degree day (HDD) data for the period 1996-2005 and forecasted HDD data for the period 2006-2015. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

FMPA forecasts demand and energy data for each All-Requirements participant using temperature data. Demands are then combined using historical coincident information to produce a coincident peak demand for the All-Requirements Project as a whole. Data reported in Table IV-8 is from the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

Q7. **Provide, on a system-wide basis, historical annual cooling degree day (CDD) data for the period 1996-2005 and forecasted CDD data for the period 2006-2015. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

Available cooling degree-day information is contained in Table IV-8. See question 6 regarding the use of temperature data.

Q8. **Provide the following data to support Schedule 4 of FMPA's Ten-Year Site Plan: the 12 monthly peak demands for the years 2003, 2004, and 2005; the date when each of these monthly peaks occurred; and the temperature at the time of these monthly peaks. Describe how FMPA derives system-wide temperature if more than one weather station is used.**

See Table IV-9 for monthly peak demand information. Temperature data reported in Table IV-9 is form the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

Q9. **Discuss the actions taken by FMPA or its members to promote and encourage competition within and among coal transportation members.**

FMPA is a joint owner in existing coal capacity with OUC. OUC is FMPA's primary coal transportation manager for Stanton Units 1 and 2. Such information may be obtained from OUC.

Q10. **Discuss any actions taken by the FMPA or its members to purchase re-gasified liquefied natural gas (LNG).**

FMPA, in coordination with a group of large municipal electric utilities in Florida, has had ongoing discussions with all of the developers of potential LNG projects that could serve Florida. This includes projects proposed out of the Bahamas as well as the proposed expansion of the Elba Island facility in Georgia that will be delivered into Florida through the Cypress Project. FMPA views LNG as an important addition to the overall supply portfolio for Florida and will continue discussions with all projects with a long term supply purchase as the ultimate goal.

Q11. **Provide documents that support FMPA's fuel price forecasts for natural gas, residual fuel oil, and distillate fuel oil for the 2006-2015 period.**

The forecast for natural gas, distillate fuel oil, and residual fuel oil was developed by FMPA through internal resources, NYMEX spot fuel pricing forecasts, and external consultants including Hill & Associates.

Table IV-1
Existing Generating Unit Operating Performance

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical [2]	Projected [3]	Historical [2]	Projected [3]	Historical [2]	Projected [3]	Historical [2]	Projected [3]
FPL/St. Lucie	2	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]
KUA/Cane Island CT	1		3.8%		3.0%		93.3%		10,402
KUA/Cane Island CC	2		5.8%		6.3%		88.3%		8,187
KUA/Cane Island CC	3		5.8%		6.3%		88.3%		7,573
OUC/Stanton	1	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Stanton	2	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Stanton	A	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Indian River CT	A	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Indian River CT	B	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Indian River CT	C	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
OUC/Indian River CT	D	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
Key West (Stock Island) CT	2		1.9%		3.0%		95.1%		15,883
Key West (Stock Island) CT	3		1.9%		3.0%		95.1%		14,914

[1] For those generating units wholly or partially owned by the All-Requirements Project
[2] Historical data represents the average of the most recent three years.
[3] Projected data represents the average of the next ten years.
[4] Historical and projected operating data for this unit is available from Florida Power & Light.
[5] Historical and projected operating data for this unit is available from Orlando Utilities Commission.

Table IV-2
Nominal, Delivered Fuel Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Residual Oil [1]		Distillate Oil		Natural Gas		Coal [2]		Nuclear	
Year	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)
History:										
2003										
2004										
2005										
Forecast:										
2006	793		1,403		855		341		50	
2007	777	-2.02%	1,399	-0.29%	798	-6.67%	338	-0.88%	50	0.00%
2008	749	-3.60%	1,367	-2.29%	755	-5.39%	319	-5.62%	50	0.00%
2009	730	-2.54%	1,346	-1.54%	719	-4.77%	269	-15.67%	50	0.00%
2010	714	-2.19%	1,328	-1.34%	693	-3.62%	272	1.12%	50	0.00%
2011	732	2.50%	1,361	2.50%	710	2.50%	284	4.41%	50	0.00%
2012	750	2.50%	1,395	2.50%	728	2.50%	291	2.46%	50	0.00%
2013	769	2.50%	1,430	2.50%	746	2.50%	299	2.75%	50	0.00%
2014	788	2.50%	1,466	2.50%	765	2.50%	309	3.34%	50	0.00%
2015	808	2.50%	1,503	2.50%	784	2.50%	320	3.56%	50	0.00%

[1] For residual oil with a sulfur content between 0.7% and 2.0%.
[2] For medium sulfur coal with a sulfur content between 1.0% and 2.0%.

Table IV-3
Nominal, Delivered Fuel Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Residual Oil [1]		Distillate Oil		Natural Gas		Coal [2]		Nuclear	
Year	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)
History:										
2003										
2004										
2005										
Forecast:										
2006	1,447		2,691		1,404		491		50	
2007	1,351	-6.67%	2,512	-6.67%	1,311	-6.67%	487	-0.88%	50	0.00%
2008	1,278	-5.39%	2,377	-5.39%	1,240	-5.39%	459	-5.62%	50	0.00%
2009	1,217	-4.77%	2,263	-4.77%	1,181	-4.77%	387	-15.67%	50	0.00%
2010	1,173	-3.62%	2,181	-3.62%	1,138	-3.62%	392	1.12%	50	0.00%
2011	1,202	2.50%	2,236	2.50%	1,167	2.50%	409	4.41%	50	0.00%
2012	1,232	2.50%	2,292	2.50%	1,196	2.50%	419	2.46%	50	0.00%
2013	1,263	2.50%	2,349	2.50%	1,226	2.50%	431	2.75%	50	0.00%
2014	1,295	2.50%	2,408	2.50%	1,257	2.50%	445	3.34%	50	0.00%
2015	1,327	2.50%	2,468	2.50%	1,288	2.50%	461	3.56%	50	0.00%

[1] For residual oil with a sulfur content between 0.7% and 2.0%.
[2] For medium sulfur coal with a sulfur content between 1.0% and 2.0%.

Table IV-4
Nominal, Delivered Fuel Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Residual Oil [1]		Distillate Oil		Natural Gas		Coal [2]		Nuclear	
Year	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)	¢/Mbtu	Escalation (%)
History:										
2003										
2004										
2005										
Forecast:										
2006	498		925		483		241		50	
2007	464	-6.67%	864	-6.67%	451	-6.67%	239	-0.88%	50	0.00%
2008	439	-5.39%	817	-5.39%	426	-5.39%	225	-5.62%	50	0.00%
2009	418	-4.77%	778	-4.77%	406	-4.77%	190	-15.67%	50	0.00%
2010	403	-3.62%	750	-3.62%	391	-3.62%	192	1.12%	50	0.00%
2011	413	2.50%	769	2.50%	401	2.50%	201	4.41%	50	0.00%
2012	424	2.50%	788	2.50%	411	2.50%	206	2.46%	50	0.00%
2013	434	2.50%	808	2.50%	422	2.50%	211	2.75%	50	0.00%
2014	445	2.50%	828	2.50%	432	2.50%	218	3.34%	50	0.00%
2015	456	2.50%	849	2.50%	443	2.50%	226	3.56%	50	0.00%

[1] For residual oil with a sulfur content between 0.7% and 2.0%.
[2] For medium sulfur coal with a sulfur content between 1.0% and 2.0%.

Table IV-5
Financial Assumptions Base Case

AFUDC Rate		5.00%
Capitalization Ratios (%):		
	Debt	100%
	Preferred	N/A
	Equity	N/A
Rate of Return (%):		
	Debt	N/A
	Preferred	N/A
	Equity	N/A
Income Tax Rate (%):		
	State	N/A
	Federal	N/A
	Effective	N/A
Other Tax Rate:		N/A
Discount Rate:		5.0%
Tax Depreciation Rate (%):		N/A

Table IV-6
Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2006	2.50%	2.50%	2.50%	2.50%
2007	2.50%	2.50%	2.50%	2.50%
2008	2.50%	2.50%	2.50%	2.50%
2009	2.50%	2.50%	2.50%	2.50%
2010	2.50%	2.50%	2.50%	2.50%
2011	2.50%	2.50%	2.50%	2.50%
2012	2.50%	2.50%	2.50%	2.50%
2013	2.50%	2.50%	2.50%	2.50%
2014	2.50%	2.50%	2.50%	2.50%
2015	2.50%	2.50%	2.50%	2.50%

Table IV-7
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2006						
2007						
2008						
2009						
2010		(See note below)			(See note below)	
2011						
2012						
2013						
2014						
2015						

Note: FMPA does not develop projections of either Isolated or Assisted Loss of Load Probability nor Expected Unserved Energy.

Table IV-8
Historical and Projected Heating and Cooling Degree Days [1]

(1) Year	(2) Annual Heating Degree Days	(3) Annual Cooling Degree Days
(a)	(b)	(c)
1996	834	3,461
1997	395	3,323
1998	621	3,490
1999	350	3,637
2000	452	3,413
2001	706	3,202
2002	457	3,591
2003	714	3,529
2004	554	3,447
2005	501	3,490
Projected Values for 2006 to 2015	580	3,428

[1] Projections are based on normal heating and cooling degree day data reported by the National Oceanic Atmospheric Administration (NOAA) and is based on the historical period from 1971-2000 inclusive. Data reported is for the Orlando International Airport (OIA) annual weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.

Table IV-9
All-Requirements Project Monthly Peak Demand Information [1] [2]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Actual - 2003				Actual - 2004				Actual - 2005			
Month	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)	Peak Demand MW	Day of Month	Max Temp (°F)	Min Temp (°F)
January	1,473	24	43	27	1,194	29	68	37	1,340	24	58	33
February	900	03	77	42	1,104	19	69	37	1,031	11	60	41
March	1,133	20	91	71	905	06	87	61	1,033	31	87	64
April	1,079	07	88	71	1,078	26	88	64	1,036	01	86	68
May	1,265	09	93	70	1,301	27	95	67	1,290	24	92	70
June	1,325	12	92	73	1,385	24	95	73	1,361	14	92	72
July	1,343	09	95	76	1,416	14	95	75	1,486	28	96	78
August	1,310	27	91	74	1,378	31	94	76	1,524	17	96	78
September	1,261	22	91	74	1,346	17	92	77	1,348	02	93	77
October	1,160	13	91	75	1,243	04	89	73	1,283	10	89	75
November	1,098	07	86	71	1,133	03	86	65	1,011	16	83	64
December	1,105	21	64	37	1,147	15	57	38	1,011	22	64	44

[1] The historical hourly demand data maintained by FMPA has improved in numerical accuracy. This may result in differences in the value and timing of monthly peak demand shown above to similar data shown in prior Ten-year Site Plans for the same year.

[2] Temperature data is taken from recordings of the Orlando International Airport weather station, which may be used as an indicator of weather conditions over FMPA's geographically diverse service area.