REPORT
March 29, 2016

Florida Municipal Power Agency

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

Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
E-Filing address: Filings@psc.state.fl.us

Re: FMPA's 2016 Ten Year Site Plan

March 31, 2016

Dear Sir/Madam:

Pursuant to Rule 25-22.071(1) Florida Administrative Code, and Staff's partial waiver of certain requirements of the Rule pursuant to an e-mail dated March 1, 2016, FMPA is hereby filing 1 electronic copy of its 2016 Ten Year Site Plan, and providing notice that 5 hardcopies are being shipped to your address above. If you have any questions, please do not hesitate to contact me at (321) 239-1013.

Sincerely,

Michele A. Jackson

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

Enc.

cc. File

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FMPA®

Florida Municipal Power Agency

Ten-Year Site Plan 2016-2025

Submitted to

Florida Public Service Commission

April 1, 2016

Community Power + Statewide Strength ®

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Executive Summary

The following information is provided in accordance with Florida Public Service Commission (PSC) Rules 25-22.070, 25-22.071, and 25-22.072, which require certain electric utilities in the State of Florida to submit a Ten-Year Site Plan (TYSP). The TYSP provides, among other things, a description of existing electric utility resources, a 10-year forecast of electric power generating needs and an identification of the general location and type of any proposed generation capacity and transmission additions for the next 10-year period.

The Florida Municipal Power Agency (FMPA or the Agency) is a project-oriented, joint-action agency. There are currently 31 Members of FMPA – each a municipal electric utility – located throughout the State of Florida. As a joint-action agency, FMPA facilitates opportunities for FMPA Members to achieve economies of scale in power generation and related services. FMPA's direct responsibility for power supply planning can be separated into two roles. First, for the 15 Participants in the All-Requirements Power Supply Project (ARP), FMPA supplies all of the electric power and energy, transmission and associated services, unless limited by a contract rate of delivery, except for certain excluded resources. Second, for member systems that do not purchase their full requirements from the ARP, the Agency's role has been to evaluate joint action opportunities and make the findings available to such members, whereby each member can elect whether or not to participate in that project. FMPA currently has four such power supply projects – the Stanton, Tri-City, Stanton II, and St. Lucie Projects. FMPA's TYSP is focused on the resources of, and planning for, the ARP.

The total summer capacity of ARP resources for the year 2016 is 1,673 MW. This capacity is comprised of ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements, and are summarized below in Table ES-1.

Table ES-1
FMPA ARP Summer 2016 Capacity Resources

Resource Category	Summer Capacity (MW)
Excluded Resources (Nuclear)	35
ARP System Generation	1,397
Power Purchases	241
Net Total 2016 ARP Resources [1]	1,673

[1] Totals may not add due to rounding

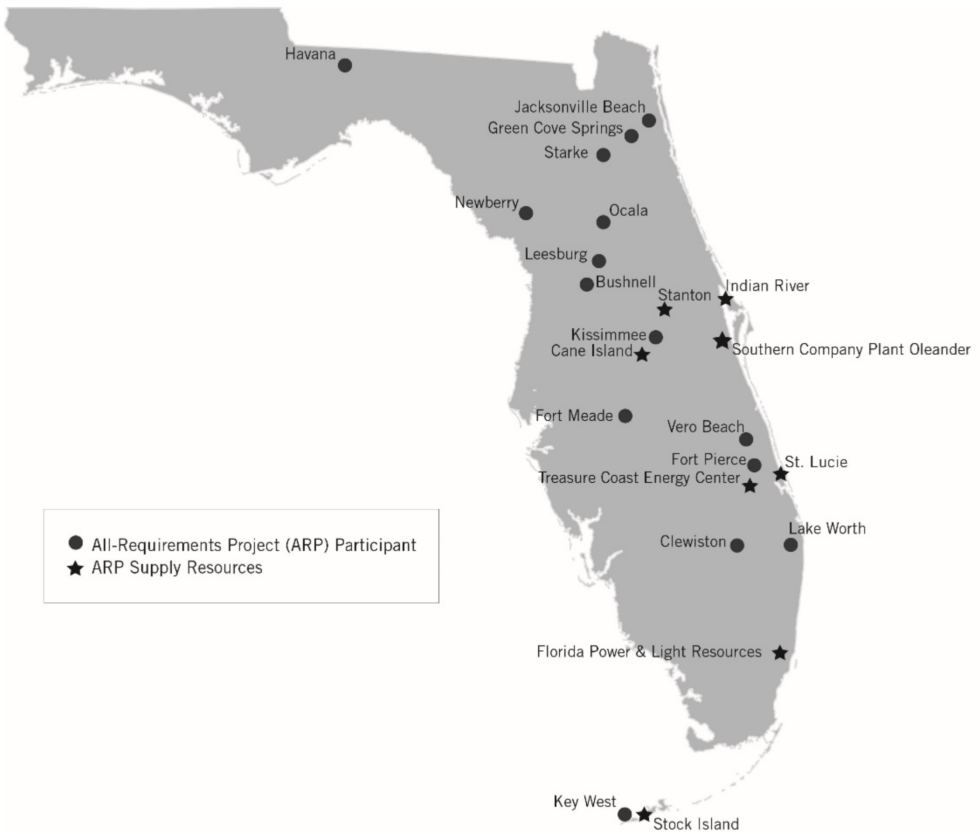
Based on the ARP's 2015 Load Forecast, the ARP expects to meet its generation capacity requirements, with an 18% reserve margin with existing resources, through 2023. FMPA will need to acquire 36 MW in 2024 and 58 MW in 2025 from undetermined sources to be able to meet generation capacity requirements with an 18% reserve margin. The projected peak native ARP summer load for 2016 is 1,224 MW and is forecasted to increase to 1,399 MW in 2025. FMPA will continue to evaluate and develop sufficient, cost-effective resource alternatives for the ARP through its integrated resource planning process.

In 2010, FMPA, on behalf of the ARP, entered into a contract to supply the full-requirements capacity and energy to the City of Quincy beyond Quincy's entitlement in a Southeastern Power Administration (SEPA) Project. The term of the contract was from January 1, 2011 through December 31, 2015.

FMPA is actively involved in planning and developing new renewable energy resources and demand side resource opportunities consistent with, and in consideration of the planning requirements of the State of Florida and the Public Utility Regulatory Policies Act (PURPA). Currently, the ARP purchases renewable energy from a cogeneration plant fueled by sugar bagasse, and utilizes landfill gas as a secondary fuel to supplement its coal fuel requirements. In December 2009, the ARP commissioned its first solar photovoltaic system, a jointly-owned 30 kW DC system located in Key West, FL. In addition, ARP-Participants are engaged in an ARP-sponsored energy conservation program.

A location map of the ARP Participants and FMPA's power resources as of December 31, 2015 is shown in Figure ES-1.

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



Section 1 Description of FMPA

1.1 FMPA

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

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

The Interlocal Cooperation Act of 1969 authorizes municipal electric utilities to cooperate with each other on the basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities. The Florida Constitution and the Joint Power Act provide the supplemental authority for municipal electric utilities to join together with public utilities, electric cooperatives, foreign public utilities and other persons, as defined, for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants.

Each city commission and council, utility commission, board, or authority that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of approving FMPA's project budgets (except for the All-Requirements Power Supply Project budget which is approved by the FMPA Executive Committee), approving new projects and project financing (except for All-Requirements Power Supply Project financing which is approved by the FMPA Executive Committee), hiring a General Manager and General Counsel, establishing by-laws that govern how FMPA operates, and creating policies that implement such by-laws. At its annual meeting, the Board elects a Chairperson, Vice Chairperson, Secretary, and Treasurer.

The Executive Committee consists of 13 members, representing the 15 participants in the All-Requirements Power Supply Project (ARP)[1]. The Executive Committee has the responsibility of approving the ARP budget and agency general budget, approving and financing ARP projects, approving ARP expenditures and contracts, and governs and manages the business and affairs of the ARP. At its annual meeting, the Executive Committee elects a Chairperson and Vice Chairperson.

1.2 All-Requirements Power Supply Project

FMPA developed the ARP to secure an adequate, economical, and reliable supply of electric capacity and energy as directed by FMPA Members. Currently, 15 FMPA Members (the ARP Participants) participate in the ARP. The geographical locations of the ARP Participants are shown in Figure 1-1.

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

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

Unless they have elected to receive power through a contract rate of delivery, ARP Participants are required to purchase all of their capacity and energy requirements above their excluded resources, if any, from the ARP pursuant to the All-Requirements Power Supply Project Contract at rates that are established by the Executive Committee to recover all ARP costs. Those non-contract rate of delivery ARP Participants that own generating resources or have entitlements in FMPA power supply projects (other than entitlements in the St. Lucie Project), contract with the ARP to sell the electric capacity and energy of their resource entitlements to the ARP.

[1] As further discussed in this section, the City of Vero Beach, City of Lake Worth and the City of Ft. Meade, have exercised the right to modify their ARP participation by implementation of a Contract Rate of Delivery (CROD). The CROD amount for both the cities of Vero Beach and Lake Worth pursuant to contract terms is 0 MW. While they remain participants in the ARP, effective January 1, 2010 (for Vero Beach) and effective January 1, 2014 (for Lake Worth), they no longer are purchasing capacity and energy from the ARP and no longer have representatives on the Executive Committee. The CROD amount for the City of Ft. Meade is 10.36 MW of capacity and energy effective January 1, 2015. The City of Ft. Meade continues to have representation on the Executive Committee.

Figure 1-1
ARP Participant Cities

On December 9, 2004, the City of Vero Beach provided notice to FMPA, pursuant to the All-Requirements Power Supply Project Contract, that it was going to exercise the right to modify its ARP full requirements membership and request and establish a Contract Rate of Delivery (CROD) which began January 1, 2010. On December 17, 2008, the City of Lake Worth provided notice to FMPA that it was going to exercise the right to modify its ARP full requirements membership and establish a CROD beginning January 1, 2014. On July 14, 2009, the City of Fort Meade provided notice to FMPA that it will also exercise its right to modify its full requirements membership and establish a CROD beginning January 1, 2015. Finally, on December 10, 2014, the City of Green Cove Springs (GCS) provided notice to FMPA that it was going to exercise the right to modify its ARP full requirements membership and establish a CROD beginning January 1, 2020. The effect of these notices is that the ARP will no longer utilize these ARP Participants' generating resources (if any), and the ARP will commence serving up to a calculated maximum amount of capacity and energy for these ARP Participants (with these ARP participants being responsible for meeting all of their electric demand in excess of FMPA's obligation). The amount of the CROD for Vero Beach and Lake Worth served by the ARP has been established as zero (0) MW, and the amount of the CROD for Fort Meade has been established as a maximum of 10.36 MW. The amount of the CROD for the City of Green Cove Springs will be determined, pursuant to contract terms by December 1, 2019.

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

City of Bushnell

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

City of Clewiston

The City of Clewiston is located in southern Florida in Hendry County. The City joined the ARP in May 1991. Danny Williams is the Director of Utilities. The City's service area is approximately 5 square miles. For more information about the City of Clewiston, please visit www.cityofclewiston.org.

City of Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City joined the ARP in February 2000. Fred Hilliard is the City Manager. The City's service area is approximately 5 square miles. For more information about the City of Fort Meade, please visit www.cityoffortmeade.com.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. FPUA joined the ARP in January 1998. Clay Lindstrom is the Director of Utilities. FPUA's service area is approximately 35 square miles. For more information about Fort Pierce Utilities Authority, please visit www.fpua.com.

City of Green Cove Springs

The City of Green Cove Springs is located in northeast Florida in Clay County. The City joined the ARP in May 1986. The City's FMPA representative is Robert C. Page. The City's service area is approximately 25 square miles. For more information about the City of Green Cove Springs, please visit www.greencovesprings.com.

Town of Havana

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

City of Jacksonville Beach

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

Utility Board of the City of Key West

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

Kissimmee Utility Authority

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

City of Lake Worth

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

City of Leesburg

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

City of Newberry

The City of Newberry is located in north central Florida in Alachua County. The City joined the ARP in December 2000. Bill Conrad is the Mayor, and Jamie Jones is the Utilities Director**.** The City's service area is approximately 3 square miles. For more information about the City of Newberry, please visit www.ci.newberry.fl.us.

City of Ocala

The City of Ocala, doing business as Ocala Utility Services, is located in central Florida in Marion County. The City joined the ARP in May 1986. John Zobler is the City Manager, and Sandra Wilson is the Deputy City Manager. The City's service area is approximately 161 square miles. For more information about Ocala Utility Services, please visit www.ocalaelectric.com.

City of Starke

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

City of Vero Beach

The City of Vero Beach is located on Florida's east coast in Indian River County. Vero Beach joined the ARP in June 1997. Dick Winger is the Mayor. The City's service area is approximately 41 square miles. For more information about the City of Vero Beach, please visit www.covb.org.

1.3 Other FMPA Power Supply Projects

In addition to the ARP, FMPA facilitates the participation of FMPA Members in four other power supply projects as discussed below.

St. Lucie Project

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

Table 1-1
St. Lucie Project Participants

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

Stanton Project

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

Table 1-2
Stanton Project Participants

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

Tri-City Project

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

Table 1-3
Tri-City Project Participants

City	% Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

Stanton II Project

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

Table 1-4
Stanton II Project Participants

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

1.4 Summary of Projects

Table 1-5 provides a summary of FMPA Member project participation as of December 31, 2015.

Table 1-5
Summary of FMPA Power Supply Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Power Supply Project	Stanton II Project
City of Alachua	X				
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X			X [3]	
Ft. Pierce Utilities Authority	X	X	X	X	X
City of Green Cove Springs	X			X [4]	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Utility Board of the City of Key West			X	X	X
Kissimmee Utility Authority	X	X		X	X
City of Lake Worth	X	X		X [2]	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X [1]	X

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

[2] Effective January 1, 2014, the City of Lake Worth exercised the right to modify its ARP full requirements membership (CROD)

[3] Effective January 1, 2015, the City of Ft. Meade exercised the right to modify its ARP full requirements membership (CROD)

[4] Effective January 1, 2020, the City of Green Cove Springs will have exercised the right to modify its ARP full requirements membership (CROD)

Section 2 Description of Existing Facilities

2.1 ARP Supply-Side Resources

The ARP supply-side resources consist of ARP Participant-owned resources, ARP Participant entitlements and ownership shares in nuclear, coal and gas-fired power plants located in the State of Florida, ARP owned resources and ownership shares in coal and gas-fired power plants located in the State of Florida, and power purchase agreements. The supply-side resources for the ARP for the 2016 summer season are shown in Table 2-1.

Table 2-1
ARP Supply-Side Resources Summer 2016

Resource Category	Summer Capacity (MW)
1) Excluded Resources (Nuclear)	35
2) ARP System Generation	
Existing	1,397
New	-
Sub Total ARP System Generation	1,397
3) Power Purchases	241
Total 2016 ARP Resources	1,673

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

1) **Excluded Resources (Nuclear):** A number of the ARP Participants participate in FMPA's St. Lucie Project, and are entitled to capacity and energy shares from St. Lucie Unit No. 2. Capacity from their entitlement shares in the St. Lucie Project is classified as an "Excluded Power Supply Resource" in the All-Requirements Power Supply Project Contract between FMPA and the ARP Participants. As such, the ARP Participants pay

their own costs associated with their entitlement in the St. Lucie Project and individually receive the benefits of the capacity and energy from the St. Lucie Project. The ARP provides the balance of capacity and energy requirements for these ARP Participants (unless otherwise limited by CROD). Full requirements ARP Participants' entitlements in the nuclear units are considered in the capacity planning for the ARP.

2) **ARP System Generation:** This category includes 1) generation that is wholly or jointly owned by FMPA as agent for the ARP; 2) generation that is wholly or jointly owned by ARP Participants; and 3) generation from ARP Participants' entitlements in the Stanton, Tri-City, and Stanton II Projects that is purchased by the ARP. FMPA has operational control of the ARP's and ARP Participants' capacity and energy from these resources, and such capacity and energy is dedicated solely to serving the ARP.

3) **Power Purchases:** This category includes power purchases between FMPA, as agent for the ARP, and third-parties. Purchased power generation used to serve the ARP as of December 31, 2015 includes capacity and energy purchased from Southern Company from their Stanton Unit A and Oleander Unit 5 facilities.

Information regarding existing ARP generation resources as of December 31, 2015, can be found in Schedule 1 at the end of this section

2.2 ARP Transmission System

The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 KV to 500 KV. Peninsular Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia boundary and along the Apalachicola River in the Florida Panhandle, referred to as the Florida – Southern Interface. FPL, Duke Energy Florida (DEF), JEA and the City of Tallahassee own the transmission tie lines at the Florida – Southern Interface. ARP Participants are interconnected to the transmission systems of FPL, DEF, OUC, JEA, Seminole Electric Cooperative Incorporated (SECI), Florida Keys Electric Cooperative Incorporated (FKEC), and Tampa Electric Company (TECO). FPUA is also interconnected and co-owns transmission facilities with the City of Vero Beach. Some ARP Participants own transmission facilities within their service territories, and the ARP has an ownership share of the transmission facilities associated with the Cane Island Power Park.

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

Ft. Meade are transmitted across the DEF transmission system. Capacity and energy for KUA is transmitted across the transmission systems of FPL, DEF and OUC.

2.2.1 ARP Participant Transmission Systems[2]

FPUA

FPUA is a municipally owned utility operating electric, water, wastewater, and natural gas utilities. The electric utility owns an internal, looped, 69kV transmission system for system load, supplied by three 138 kV to 69 kV autotransformers, two at Hartman Substation and one at Garden City substation. FPUA supplies power to its distribution system at 13.2 kV via six 69 kV substations.. There are two interconnection points with other utilities, both at 138 kV. FPUA's Hartman Substation interconnects with FPL's Emerson Substation via one transmission line, and FPL's Midway Substation via two transmission lines. The Emerson and Midway #2 lines have FPL tapped substations along their route. The second interconnection point for FPUA is from the jointly-owned transmission facilities of FPUA and the City of Vero Beach at County Line Substation. County Line Substation No. 20 connects FPL's Emerson Substation to Vero Beach's South Substation and FPUA's Garden City (No. 2) Substation, via three single circuit 138-kV transmission lines. FPUA and Vero Beach jointly own the County Line Substation, the connecting lines to FPL's Emerson Substation, and the 138kV tie lines between the two municipal utilities.

KEYS

KEYS maintains and operates an electric generation, transmission, and distribution system, which supplies electric capacity and energy south of FKEC's Marathon Substation to the Lower Florida Keys and the City of Key West. KEYS and FKEC jointly own a 64 mile long 138 kV transmission system that connects from FKEC's Marathon Substation to FPL's Florida City Substation at the Dade/Monroe County Line via several FKEC 138-kV substations. A second interconnection with FPL 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. All the jointly owned 138-kV facilities are independently operated by FKEC. KEYS owns a 49.2 mile long 138 kV radial transmission system from Marathon Substation to KEYS' Stock Island Substation. The KEYS radial 138-kV system loops in and out of KEYS' Big Pine and Big Coppitt Substations and taps off at Cudjoe Key Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has six 69 kV and four 138 kV substations which supply power at 13.8 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution

[2] The City of Vero Beach and the City of Lake Worth's transmission systems descriptions are not being provided because these cities directly report to the FRCC on their own systems.

line. KEYS/FMPA installed STATCOMS and shunt capacitors at Big Pine and Stock Island Substations in the summer of 2012. A series capacitor at Islamorada Substation was installed and commissioned in November, 2014 in conjunction with FKEC; and an automated transmission protection system to automatically shed load post-contingency commissioned in August, 2015. These projects increased the import limit of the Florida Keys (KEYS/FMPA and FKEC) 138 kV transmission system, allowing it to be equal to its thermal limit.

KUA

KUA serves a total area of approximately 85 square miles, and owns 24.6 circuit miles of 230 kV and 48.8 circuit miles of 69 kV transmission lines that deliver capacity and energy to 10 distribution substations. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. KUA has direct transmission interconnections with DEF, OUC, TECO and the City of St. Cloud (STC) in the following locations: (1) At Cane Island Substation, one 230 kV transmission line to DEF's Intercession City Substation, one 230 kV transmission line to OUC's Taft Substation, and one 230 kV transmission line to OUC/TECO's Osceola Substation; (2) at KUA's Marydia Substation, one 230 kV transmission line to OUC's Taft Substation; (3) At KUA's Lake Cecile Substation, one 69 kV transmission line to DEF's Lake Bryan Substation; (4) At KUA's Employee Substation, one 69 kV transmission line to DEF's Meadow Woods East Substation; (5) At KUA's Buenaventura Lakes Substation, one 69 kV transmission line to OUC's Taft substation (230 to 69 kV autotransformer owned by OUC) and (6) At KUA's Cark A, Wall Substation, one 69 kV line to STC's Central Substation .

Ocala Utility Services

Ocala Utility Services (OUS) owns its bulk power supply system which consists of three 230 kV to 69 kV substations, 13 miles of radial 230 kV transmission, 67.1 miles of a 69 kV transmission loop, and 18 – 69 kV distribution substations delivering power at 12.47 kV. The distribution system consists of 759 miles of overhead lines and 384 miles of underground lines.

OUS' 230 kV transmission system interconnects with DEF's Silver Springs Switching Station and Seminole Electric Cooperative, Inc.'s (SECI) Silver Springs North Switching Station. OUS' Dearmin Substation interconnects to both DEF's Silver Springs Switching Station and SECI's Silver Springs North Switching Stations. OUS' Ergle and Shaw substations are interconnected at SECI's Silver Springs North Switching Station. OUS also has a 69 kV radial tie from its Airport 69 kV Substation to Sumter Electric Cooperative's Martel Substation. OUS owns a 13 mile 230 kV transmission line from Shaw Substation to Silver Springs North Switching Station.

Beaches

Beaches owns and maintains a 138 kV transmission system that supplies electric capacity and energy to its distribution substations, with connections to both FPL and JEA. Beaches owns the 230 kV Sampson transmission switching station that interconnects to FPL at FPL's Orangedale Substation and to JEA at JEA's Switzerland Substation. Beaches has a second interconnection that ties to JEA's Neptune Beach Substation from its Penman Substation at 138 kV.

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

City of Clewiston

The City of Clewiston owns the 138 kV McCarthy transmission switching station that interconnects to FPL at FPL's Okeelanta and Ft. Myers substations via several tapped FPL 138-kV distribution stations. Clewiston owns two radial 3.5 mile 138 kV transmission lines from its McCarthy substation to the City of Clewiston substation. Two transformers at the City of Clewiston substation provide transformation from 138 kV to 12.47 kV to its distribution system. One 138 kV to 13.8 kV transformer at the City of Clewiston Substation provides a connection to the US Sugar co-generation facility.

2.2.2 ARP Transmission Agreements

OUC provides transmission service for delivery of power associated with ARP Participants' entitlements in Stanton, Tri-City and Stanton II Projects, and the ARP's ownership interests in Stanton Units 1 and 2. OUC also provides transmission service for delivery of power associated with ARP ownership interests in the Stanton A combined cycle (CC), and the Indian River combustion turbine (CT) units, as well as any additional ARP power purchases from Stanton A. OUC transmission service is for the delivery of this energy to either the FPL or DEF interfaces with OUC for subsequent delivery to ARP Participants. Rates for such transmission wheeling service from the Stanton and Indian River units are pursuant to the terms and conditions of Firm Transmission Service Agreements, and rates for transmission service for wheeling service from Stanton A are pursuant to OUC's OATT.

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

Schedule 1
Existing Generating Facilities as of December 31, 2015

(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 [1]	
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	MM/YY	MM/YY	MW	Summer (MW)	Winter (MW)
Excluded Resources												
St. Lucie	2	St. Lucie	NP	UR	-	TK	-	08/83	NA	891	35 [2]	37 [2]
Total Excluded Resources											35	37
ARP System Generation												
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-	07/87	NA	465	92 [3]	92 [3]
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-	06/96	NA	465	85 [4]	85 [4]
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	10/03	NA	671	43 [5]	45 [5]
Indian River	CT A	Brevard	GT	NG	DFO	PL	TK	06/89	NA	41	19 [6]	24 [6]
Indian River	CT B	Brevard	GT	NG	DFO	PL	TK	07/89	NA	41	19 [6]	24 [6]
Indian River	CT C	Brevard	GT	NG	DFO	PL	TK	08/92	NA	130	22 [7]	26 [7]
Indian River	CT D	Brevard	GT	NG	DFO	PL	TK	10/92	NA	130	22 [7]	26 [7]
Cane Island	1	Osceola	GT	NG	DFO	PL	TK	01/95	NA	40	35 [8]	38 [8]
Cane Island	2	Osceola	CC	NG	DFO	PL	TK	06/95	NA	122	109 [8]	113 [8]
Cane Island	3	Osceola	CC	NG	DFO	PL	TK	01/02	NA	280	240 [8]	250 [8]
Cane Island	4	Osceola	CC	NG	-	PL	TK	08/11	NA	315	300	310
Stock Island	CT1	Monroe	GT	DFO	-	WA	-	11/78	NA	20	18 [9]	18 [9]
Stock Island	CT2	Monroe	GT	DFO	-	WA	-	06/99	NA	21	16	16
Stock Island	CT3	Monroe	GT	DFO	-	WA	-	06/99	NA	21	14	14
Stock Island	GT4	Monroe	GT	DFO	-	WA	-	06/06	NA	61	46	46
Stock Island	MSD1	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8 [9]	8 [9]
Stock Island	MSD2	Monroe	IC	DFO	-	WA	-	06/91	NA	9	8 [9]	8 [9]
Stock Island	EP2	Monroe	IC	DFO	-	WA	-	07/12	NA	2	2 [9]	2 [9]
Treasure Coast	1	St. Lucie	CC	NG	DFO	PL	TK	05/08	NA	315	300	310
Total ARP System Generation											1,397	1,455
Total Generation Resources											1,432	1,491

[1] Capabilities shown are as of December 31, 2015. Net capabilities shown for the Stanton and Indian River resources reflect the ARP's ownership capacity less losses across OUC's transmission system, which were assumed to be 2 percent over the study period.

[2] Amounts shown reflect non-CROD ARP Participants' Power Entitlement Shares in the St. Lucie Project.

[3] Amounts shown reflect the ARP's (6.5060%) and KUA's (4.8193%) ownership interests in Stanton 1, as well as non-CROD ARP Participants' Power Entitlement Shares in the Stanton and Tri-City Projects.

[4] Amounts shown reflect the ARP's (5.1724%) ownership interest in Stanton 2, as well as non-CROD ARP Participants' Power Entitlement Entitlement Shares in the Stanton II Project.

[5] Amounts shown reflect the ARP's (3.5%) and KUA's (3.5%) ownership interests in Stanton A.

[6] Amounts shown reflect the ARP's (39.0%) and KUA's (12.2%) ownership interests in Indian River CTs A&B.

[7] Amounts shown reflect the ARP's (21.0%) ownership interest in Indian River CTs C&D.

[8] The ARP and KUA each own 50% of Cane Island Units 1-3. Amounts shown reflect the entire capability for each unit. FMPA has operational control of the units, which are dedicated entirely to serving the capacity and energy requirements of the ARP.

[9] Key West owns 100% of these units. FMPA has operational control of the units, which are dedicated entirely to serving the capacity and energy requirements of the ARP.

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

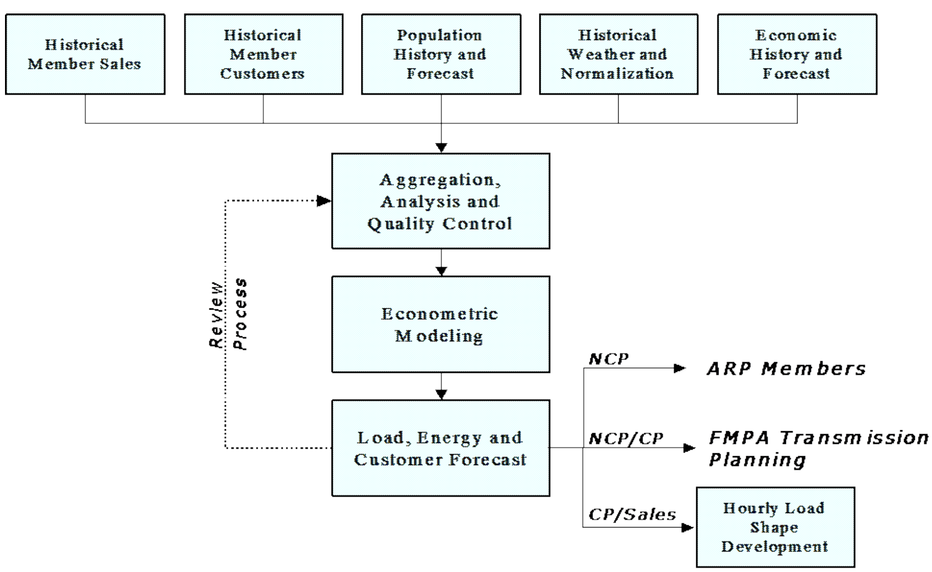
3.1 Introduction

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

3.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP Participants. Forecasts are prepared on an individual Participant basis and are then aggregated into projections of the total ARP demand and energy requirements. Projections of the total ARP demand and energy requirements as of the 2016 Ten Year Site Plan include real power losses on the transmission systems used by FMPA to deliver requirements to the ARP Participants: Thus, these projections are now on an "as generated" basis, instead of an "as delivered" basis as shown in prior Ten Year Site Plans. Figure 3-1 below identifies FMPA's load forecast process.

Figure 3-1
Load Forecast Process



Note on Figure 3-1:

NCP is the Non-Coincident Peak demand, which represents the maximum hourly demand for an ARP Participant in a given month.

CP is the Coincident Peak demand which represents the maximum hourly demand of the ARP system in aggregate, or the hourly demand of the ARP Participant at the time of the ARP CP.

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

3.3 Load Forecast Overview

The load and energy forecast (Forecast) was prepared for a 20 year period, beginning fiscal year 2015 through 2034. The Forecast was prepared on a monthly basis using municipal utility data provided to FMPA by the ARP Participants and load data maintained by FMPA. Historical and projected economic and demographic data were provided by IHS Global Insight and Woods & Poole Economics, nationally recognized providers of such data, from which averages were developed for the forecast horizon. The Forecast also relied on information regarding local economic and demographic issues specific to each ARP Participant. Weather data was provided by the National Oceanic and Atmospheric Administration (NOAA) for a variety of weather stations in close proximity to the ARP Participants. The Forecast assumes normal weather conditions, as reported by NOAA and reflecting the 1981-2010 period.

The Forecast reflects the City of Fort Meade's establishment of Contract Rate of Delivery (CROD) effective on January 1, 2015, and FMPA's obligation to serve up to a maximum of 10.36 MW of the load requirements of Fort Meade. The results of the Base Case forecast are discussed in Section 3.6.1.

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

3.4 Methodology

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

In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures. Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. 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 Participant. In some cases, rate classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater stability is provided in the historical period upon which statistical relationships are based.

3.4.1 Model Specifications

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

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

The non-residential electricity sales models reflect that energy sales are best explained by: (i) real retail sales, total personal income, or gross domestic product (GDP) as a measure of economic activity and population in and around the ARP Participant's service territory, (ii) the real price of electricity, and (iii) weather variables. For certain large non-residential customers, the forecast was based on assumptions developed in consultation with the Participants (e.g., Clewiston and Key West).

Weather variables include heating and cooling degree days for the current month and for the prior month. Lagged degree day variables are included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month.

3.4.2 Projection of NEL and Peak Demand

The forecasts of sales for each rate classification described above were summed to equal the total retail sales of each ARP Participant. An assumed distribution system loss factor, based either on a regression analysis or a recent average of historical distribution system loss factors, was then applied to the total sales to derive monthly delivered net energy for load (NEL).

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted delivered NEL on a total ARP Participant system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period 2000-2014.

Monthly peak demand was based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period typically occurs during July or August of each 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.

Once the monthly NEL and Peak Demand requirements were projected for each ARP Participant on an as delivered basis, expected losses on the transmission systems used to deliver the requirements, using assumed Real Power Loss percentages throughout the forecasted period, were added in to arrive at NEL and Peak Demand requirements on an as generated basis. These are summed across all ARP Participants for the ARP's total demand and energy requirements.

3.5 Data Sources

3.5.1 Historical ARP Participant Retail Sales Data

Data was generally available and analyzed over January 1993 through December 2014. Data included historical customer counts, sales, and revenues by rate classification for each of the ARP Participants.

3.5.2 Weather Data

Historical weather data was provided by the National Climatic Data Center (a subsidiary of the National Oceanic and Atmospheric Administration) (NCDC). Weather stations, from which historical weather was obtained, were selected by their quality and proximity to the ARP Participants. In most cases, the closest "first-order" weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data. In two cases (Beaches and FPUA), however, weather data from a "cooperative" weather station, which was closer than the closest first-order station, appeared to more accurately reflect the weather conditions that affect the ARP Participants' loads, based on statistical measures, than the closest first-order weather station.

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

Normal weather conditions have been assumed in the projected period. Thirty-year normal monthly HDD and CDD are based on average weather conditions from 1981 through 2010, as reported by NOAA.

3.5.3 Economic Data

IHS Global Insight and Woods & Poole Economics, both nationally recognized providers of economic data, provided both historical and projected economic and demographic data for each of the 14 counties in which the ARP Participants' service territories reside (the service territory of

Beaches includes portions of both Duval and St. Johns Counties). This data includes county population, households, employment, personal income, retail sales, and gross domestic product. Although all of the data was not necessarily used in each of the forecast equations, each was examined for its potential to explain changes in the ARP Participants' historical electric sales.

3.5.4 Real Electricity Price Data

The real price of electricity was derived from a twelve month or multi-year moving average of real average revenue. Projected real electricity prices were assumed to increase at a rate of 0.5% per year, generally based on projections provided by the Energy Information Administration in the 2014 Annual Energy Outlook for Florida.

3.6 Overview of Results

3.6.1 Base Case Forecast

The results of the Forecast show that the net energy for load (NEL) to be supplied to ARP Participants is expected to grow at an annual average growth rate of 1.5% from 2015-2024, and at 1.2% from 2025-2034. The Base Case ARP forecast summer coincident peak (CP) demand and NEL for Calendar Year 2016 are 1,224 MW and 5,894 GWh, respectively.

3.6.2 Weather-Related Uncertainty of the Forecast

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

The potential weather variability was developed using weather data specific to each weather station generally over the period 1970-2013. These weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, although this is less likely to happen than severe conditions in one season or the other. Accordingly, it should be recognized that annual NEL may be somewhat less volatile than the annual NEL variation shown herein. Conversely, NEL in any particular month may be *more* volatile than shown herein. Finally, because the forecast methodology derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand are effectively assumed to have the same weather-related volatility as annual NEL.

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

3.7 Load Forecast Schedules

Schedules 2.1 through 2.3 and 3.1 through 3.3 present the Base Case load forecast. Schedules 3.1a and 3.2a present the low, or Mild weather case, and Schedules 3.1b and 3.2b present the high or Severe weather case. Schedule 4 presents the actual (2015) and forecasted (Base Case for 2016 and 2017) peak demand and NEL by month.

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)
	Residential					Commercial		
Year [1]	Population Served by ARP Participants	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
2006	NA	NA	3,293	244,195	13,487	3,356	45,180	74,284
2007	NA	NA	3,273	248,455	13,173	3,407	45,717	74,531
2008	NA	NA	3,127	248,305	12,593	3,365	46,521	72,333
2009	NA	NA	3,169	248,675	12,743	3,232	45,999	70,253
2010	NA	NA	2,951	220,301	13,395	2,835	40,174	70,575
2011	NA	NA	2,850	222,080	12,831	2,803	40,139	69,822
2012	NA	NA	2,724	224,555	12,132	2,778	40,185	69,119
2013	NA	NA	2,755	226,586	12,159	2,771	40,407	68,586
2014	NA	NA	2,614	207,882	12,576	2,574	37,780	68,129
2015	NA	NA	2,772	210,980	13,136	2,679	38,337	69,890
2016	NA	NA	2,698	213,642	12,629	2,664	38,569	69,059
2017	NA	NA	2,740	216,557	12,651	2,704	39,034	69,266
2018	NA	NA	2,787	219,498	12,699	2,745	39,504	69,497
2019	NA	NA	2,835	222,029	12,767	2,787	39,966	69,738
2020	NA	NA	2,879	224,419	12,829	2,829	40,433	69,978
2021	NA	NA	2,922	226,814	12,882	2,872	40,906	70,214
2022	NA	NA	2,964	229,112	12,936	2,915	41,377	70,446
2023	NA	NA	3,007	231,364	12,995	2,958	41,848	70,678
2024	NA	NA	3,050	233,603	13,057	3,001	42,314	70,913
2025	NA	NA	3,094	235,798	13,122	3,043	42,767	71,151

[1] Amounts shown for 2006 through 2015 represent historical values. Amounts shown for 2016 through 2025 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year [1]	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales GWh	Total Sales to Ultimate Customers GWh
2006	11	1	11,480,000	0	61	110	6,832
2007	20	1	19,516,750	0	62	114	6,876
2008	4	1	3,694,000	0	63	116	6,674
2009	6	1	5,889,000	0	64	114	6,584
2010	3	1	2,862,000	0	60	109	5,958
2011	3	1	2,653,000	0	60	106	5,821
2012	3	1	2,738,000	0	60	104	5,668
2013	2	1	1,983,000	0	60	101	5,690
2014	3	1	2,512,000	0	55	107	5,353
2015	2	1	1,767,700	0	55	110	5,617
2016	2	1	2,301,600	0	55	105	5,524
2017	2	1	2,301,600	0	55	105	5,606
2018	2	1	2,301,600	0	56	106	5,696
2019	2	1	2,301,600	0	56	106	5,786
2020	2	1	2,301,600	0	56	106	5,874
2021	2	1	2,301,600	0	57	107	5,960
2022	2	1	2,301,600	0	57	107	6,046
2023	2	1	2,301,600	0	58	108	6,132
2024	2	1	2,301,600	0	58	109	6,220
2025	2	1	2,301,600	0	59	109	6,307

[1] Amounts shown for 2006 through 2015 represent historical values. Amounts shown for 2016 through 2025 represent forecast values.
[2] Loads and customer counts only reflects the ARP. Quincy's loads are shown as Sale for Resale on Schedule 2.3.

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

(1)	(2)	(3)	(4)	(5)	(6)
Year [1]	Sales for Resale GWh [2]	Utility Use & Losses GWh [3]	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
2006	0	469	7,301	0	289,376
2007	0	461	7,337	0	294,173
2008	0	380	7,053	0	294,827
2009	0	396	6,980	0	294,675
2010	0	406	6,364	0	260,476
2011	107	298	6,225	0	262,219
2012	98	379	6,145	0	264,741
2013	132	356	6,178	0	266,994
2014	134	334	5,821	0	245,663
2015	118	337	6,072	0	249,318
2016	0	370	5,894	0	252,212
2017	0	380	5,987	0	255,592
2018	0	386	6,082	0	259,003
2019	0	391	6,177	0	261,996
2020	0	400	6,274	0	264,853
2021	0	401	6,361	0	267,721
2022	0	406	6,452	0	270,491
2023	0	411	6,544	0	273,213
2024	0	421	6,641	0	275,917
2025	0	422	6,729	0	278,566

[1] Amounts shown for 2006 through 2015 represent historical values. Amounts shown for 2016 through 2025 represent forecast values.
[2] Sales to cover Quincy's loads are shown as Sale for Resale
[3] Includes ARP Participant Use, Distribution Losses within the service territory of ARP Participants, and Transmission Losses to serve ARP Participants and other Sales for Resale.

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

(1) Year [1]	(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	1,496	1,496	0	0	0	0	0	0	1,496
2007	1,540	1,540	0	0	0	0	0	0	1,540
2008	1,468	1,468	0	0	0	0	0	0	1,468
2009	1,500	1,500	0	0	0	0	0	0	1,500
2010	1,286	1,286	0	0	0	0	0	0	1,286
2011	1,301	1,301	0	0	0	0	0	0	1,301
2012	1,237	1,237	0	0	0	0	0	0	1,237
2013	1,265	1,265	0	0	0	0	0	0	1,265
2014	1,227	1,227	0	0	0	0	0	0	1,227
2015	1,235	1,235	0	0	0	0	0	0	1,235
2016	1,224	1,224	0	0	0	0	0	0	1,224
2017	1,242	1,242	0	0	0	0	0	0	1,242
2018	1,262	1,262	0	0	0	0	0	0	1,262
2019	1,282	1,282	0	0	0	0	0	0	1,282
2020	1,303	1,303	0	0	0	0	0	0	1,303
2021	1,321	1,321	0	0	0	0	0	0	1,321
2022	1,340	1,340	0	0	0	0	0	0	1,340
2023	1,360	1,360	0	0	0	0	0	0	1,360
2024	1,380	1,380	0	0	0	0	0	0	1,380
2025	1,399	1,399	0	0	0	0	0	0	1,399

[1] Amounts shown for 2006 through 2015 represent historical values. Amounts shown for 2016 through 2025 represent forecast values.

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

(1) Year [1]	(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	1,419	1,419	0	0	0	0	0	0	1,419
2006/07	1,217	1,217	0	0	0	0	0	0	1,217
2007/08	1,347	1,347	0	0	0	0	0	0	1,347
2008/09	1,436	1,436	0	0	0	0	0	0	1,436
2009/10	1,426	1,426	0	0	0	0	0	0	1,426
2010/11	1,271	1,271	0	0	0	0	0	0	1,271
2011/12	1,133	1,133	0	0	0	0	0	0	1,133
2012/13	1,041	1,041	0	0	0	0	0	0	1,041
2013/14	1,035	1,035	0	0	0	0	0	0	1,035
2014/15	1,161	1,161	0	0	0	0	0	0	1,161
2015/16	1,124	1,124	0	0	0	0	0	0	1,124
2016/17	1,146	1,146	0	0	0	0	0	0	1,146
2017/18	1,164	1,164	0	0	0	0	0	0	1,164
2018/19	1,183	1,183	0	0	0	0	0	0	1,183
2019/20	1,202	1,202	0	0	0	0	0	0	1,202
2020/21	1,219	1,219	0	0	0	0	0	0	1,219
2021/22	1,237	1,237	0	0	0	0	0	0	1,237
2022/23	1,256	1,256	0	0	0	0	0	0	1,256
2023/24	1,275	1,275	0	0	0	0	0	0	1,275
2024/25	1,292	1,292	0	0	0	0	0	0	1,292

[1] Amounts shown for 2005/06 through 2014/15 represent historical values. Amounts shown for 2015/16 through 2024/25 represent forecast values.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year [1]	Total Sales to Ultimate Customers (including Sales for Resale)	Residential Conservation	Commercial/ Industrial Conservation	Utility Use & Losses	Net Energy for Load	Load Factor % [2]
2006	6,832	0	0	469	7,301	56%
2007	6,876	0	0	461	7,337	54%
2008	6,674	0	0	380	7,053	55%
2009	6,584	0	0	396	6,980	53%
2010	5,958	0	0	406	6,364	51%
2011	5,927	0	0	298	6,225	55%
2012	5,766	0	0	379	6,145	57%
2013	5,822	0	0	356	6,178	56%
2014	5,487	0	0	334	5,821	54%
2015	5,735	0	0	337	6,072	56%
2016	5,524	0	0	370	5,894	55%
2017	5,606	0	0	380	5,987	55%
2018	5,696	0	0	386	6,082	55%
2019	5,786	0	0	391	6,177	55%
2020	5,874	0	0	400	6,274	55%
2021	5,960	0	0	401	6,361	55%
2022	6,046	0	0	406	6,452	55%
2023	6,132	0	0	411	6,544	55%
2024	6,220	0	0	421	6,641	55%
2025	6,307	0	0	422	6,729	55%

[1] Amounts shown for 2006 through 2015 represent historical values. Amounts shown for 2016 through 2025 represent forecast values.
[2] The load factor reflects the annual calendar peak in the denominator (rather than, for example, the summer peak).

Schedule 3.1a
Forecast of Summer Peak Demand (MW)
All-Requirements Project – Low Case [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
2016	1,180	1,180	0	0	0	0	0	0	1,180
2017	1,197	1,197	0	0	0	0	0	0	1,197
2018	1,216	1,216	0	0	0	0	0	0	1,216
2019	1,236	1,236	0	0	0	0	0	0	1,236
2020	1,256	1,256	0	0	0	0	0	0	1,256
2021	1,274	1,274	0	0	0	0	0	0	1,274
2022	1,292	1,292	0	0	0	0	0	0	1,292
2023	1,311	1,311	0	0	0	0	0	0	1,311
2024	1,331	1,331	0	0	0	0	0	0	1,331
2025	1,349	1,349	0	0	0	0	0	0	1,349

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

Schedule 3.1b
Forecast of Summer Peak Demand (MW)
All-Requirements Project – High Case [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
2016	1,273	1,273	0	0	0	0	0	0	1,273
2017	1,291	1,291	0	0	0	0	0	0	1,291
2018	1,312	1,312	0	0	0	0	0	0	1,312
2019	1,333	1,333	0	0	0	0	0	0	1,333
2020	1,355	1,355	0	0	0	0	0	0	1,355
2021	1,374	1,374	0	0	0	0	0	0	1,374
2022	1,394	1,394	0	0	0	0	0	0	1,394
2023	1,414	1,414	0	0	0	0	0	0	1,414
2024	1,436	1,436	0	0	0	0	0	0	1,436
2025	1,455	1,455	0	0	0	0	0	0	1,455

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

Schedule 3.2a
Forecast of Winter Peak Demand (MW)
All-Requirements Project – Low Case [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
2015/16	1,083	1,083	0	0	0	0	0	0	1,083
2016/17	1,104	1,104	0	0	0	0	0	0	1,104
2017/18	1,122	1,122	0	0	0	0	0	0	1,122
2018/19	1,140	1,140	0	0	0	0	0	0	1,140
2019/20	1,158	1,158	0	0	0	0	0	0	1,158
2020/21	1,175	1,175	0	0	0	0	0	0	1,175
2021/22	1,192	1,192	0	0	0	0	0	0	1,192
2022/23	1,210	1,210	0	0	0	0	0	0	1,210
2023/24	1,228	1,228	0	0	0	0	0	0	1,228
2024/25	1,245	1,245	0	0	0	0	0	0	1,245

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

Schedule 3.2b
Forecast of Winter Peak Demand (MW)
All-Requirements Project – High Case [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
2015/16	1,170	1,170	0	0	0	0	0	0	1,170
2016/17	1,192	1,192	0	0	0	0	0	0	1,192
2017/18	1,212	1,212	0	0	0	0	0	0	1,212
2018/19	1,232	1,232	0	0	0	0	0	0	1,232
2019/20	1,251	1,251	0	0	0	0	0	0	1,251
2020/21	1,269	1,269	0	0	0	0	0	0	1,269
2021/22	1,288	1,288	0	0	0	0	0	0	1,288
2022/23	1,307	1,307	0	0	0	0	0	0	1,307
2023/24	1,327	1,327	0	0	0	0	0	0	1,327
2024/25	1,345	1,345	0	0	0	0	0	0	1,345

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

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2016	5,321	0	0	5,321	0	362	5,683	53%
2017	5,401	0	0	5,401	0	372	5,773	54%
2018	5,487	0	0	5,487	0	378	5,865	55%
2019	5,573	0	0	5,573	0	383	5,957	55%
2020	5,658	0	0	5,658	0	392	6,050	56%
2021	5,741	0	0	5,741	0	394	6,135	56%
2022	5,823	0	0	5,823	0	399	6,222	56%
2023	5,907	0	0	5,907	0	404	6,311	57%
2024	5,991	0	0	5,991	0	413	6,404	57%
2025	6,075	0	0	6,075	0	414	6,489	57%

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

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2016	5,750	0	0	5,750	0	377	6,127	57%
2017	5,836	0	0	5,836	0	387	6,224	58%
2018	5,930	0	0	5,930	0	393	6,323	59%
2019	6,024	0	0	6,024	0	398	6,422	59%
2020	6,115	0	0	6,115	0	408	6,524	60%
2021	6,205	0	0	6,205	0	409	6,614	60%
2022	6,294	0	0	6,294	0	414	6,708	61%
2023	6,384	0	0	6,384	0	419	6,804	61%
2024	6,475	0	0	6,475	0	430	6,905	61%
2025	6,567	0	0	6,567	0	430	6,996	62%

[1] Values represent predicted net energy for load under severe 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 - 2015		Forecast - 2016		Forecast - 2017	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	880	438	1,124	456	1,146	466
February	1,161	404	1,035	397	1,055	402
March	878	446	861	415	879	424
April	978	482	932	440	946	447
May	1,140	545	1,075	509	1,090	517
June	1,235	584	1,173	560	1,190	568
July	1,184	607	1,174	606	1,191	615
August	1,211	604	1,224	613	1,242	622
September	1,172	554	1,116	542	1,132	550
October	1,063	493	1,036	487	1,051	494
November	1,036	462	830	415	844	421
December	878	451	854	453	868	460

Section 4 Renewable Resources and Conservation Programs

4.1 Introduction

FMPA continually evaluates renewable and conservation resource opportunities as part of its integrated resource planning process for the ARP. The ARP currently utilizes renewable energy resources as part of the generation portfolio, including solar photovoltaic (PV) and biomass. In addition, the ARP operates a Conservation & Energy Efficiency Program and a Net Metering Program.

4.2 Renewable Resources

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

4.2.1 Solar Photovoltaic

In December 2009, the ARP completed construction on a 30 kW (DC) solar photovoltaic (PV) project located in Key West, FL. This project was developed and constructed as a joint partnership between the National Oceanic and Atmospheric Administration (NOAA) and FMPA. FMPA receives 62% of the energy generated from the solar PV system. Since the completion of the project, FMPA has received approximately 174,380 kWh of energy from the system. In 2015, FMPA's share of energy production amounted to 28,509 kWh.

FMPA continues to evaluate new opportunities for Solar PV projects for the ARP. Currently, the Executive Committee is considering the development of a utility-scale solar PV project.

4.2.2 Biomass

FMPA currently receives biomass renewable energy from two sources.

- FMPA purchases as-available power from a cogeneration plant owned and operated by U.S. Sugar Corporation. The U.S. Sugar cogeneration plant is fueled by sugar bagasse, a byproduct of sugar production. U.S. Sugar Corporation uses the bagasse to fuel their generation plants to provide power for their processes. FMPA purchases the excess power produced from these generators. During 2015, FMPA purchased 25,376 MWh of energy from this renewable resource.

- In 2015, the Stanton Units 1 and 2 consumed 866,178 MMBtu of landfill gas as a supplemental fuel source. The ARP receives energy from both the ARP's and ARP Participants' shares in the Stanton Energy Center Units 1 and 2, which amount to 21.2% of the energy output of Stanton Unit 1 and 19.3% of the energy output of Unit 2 as of December 31, 2015. Thus, the ARP utilized 173,493 MMBtu of landfill gas as a supplemental fuel source.

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

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

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

4.3 Conservation & Energy Efficiency Program

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

Conservation programs offered by ARP Participants include, but are not limited to, the following:

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

Since the inception of the program in 2008, the ARP Participants have allocated more than $5.9 million to the ARP Conservation Program. The ARP Participants recurrently evaluate evolving conservation measures, and add those measures to their respective portfolio of offerings. FMPA supports these efforts by developing engineering assumptions to track the savings associated with new measures that are adopted, and has developed a historical tracking model to integrate participation statistics and estimated energy and demand savings per year since the inception of the program.

FMPA is currently not including the effects of its energy efficiency programs in its forecast of demand and net energy for load as the program results are still under FMPA's designated threshold for level of significance developed pursuant to NERC Reliability Standards for load and demand modeling. FMPA has developed reporting tools and techniques in order to be able to estimate program effects on demand and NEL and understand the level of significance of the program. Once the threshold is crossed, FMPA will separately account for the effects of the energy efficiency program in its demand and load forecast. To the extent that recent energy efficiency efforts have been captured in actual consumption data for the last few years, the effects of the program are included in the current load forecast.

4.4 Net Metering Program

In June 2008, the ARP Participants adopted a Net Metering Policy to permit interconnection of customer-owned renewable generation to its Members' distribution system. This policy facilitates the purchase of excess customer-owned renewable generation and outlines the metering, billing and crediting procedures to be followed by ARP Participants. Thus, through the Net Metering Program the ARP has been able to switch the fuel used to provide the energy to certain residential and commercial customer loads from traditional ARP fuel sources to PV. As of December 2015, ARP Participants had approximately 2,348 kW of solar photovoltaic renewable generation (DC) connected to the grid through their net metering programs.

As with the conservation programs, FMPA is currently not including the effects of its Participants' net metering programs in its forecast of demand and net energy for load as the program results are still under FMPA's designated threshold for level of significance. However, to the extent that the net metering program has resulted in reduced customer consumption of utility generated electricity in the recent past, such impacts have been captured in actual consumption data, and the effects of the program are included in the current load forecast through the embedded reductions in actual data resulting from the program.

4.5 Load Management Program

Currently, there are no ARP-sponsored load management programs in place. FMPA continues to evaluate load management technologies in order to identify cost-effective load management programs for the ARP.

Section 5 Forecast of Facilities Requirements

5.1 ARP Planning Process

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

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

5.2 Planned ARP Generating Facility Requirements

Based upon FMPA's current Base Load forecast, the ARP currently does not require any additional resources until the summers of 2024 and 2025, when it will need to acquire 36 MW and 58 MW, respectively, from undesignated sources to maintain FMPA's 18% reserve margin. Schedule 8 at the end of this section shows planned and prospective ARP generating resources changes during the next 10-year period.

5.3 Capacity and Power Purchase Requirements

The current system firm power supply purchase resources of the ARP include two purchases from Southern Company. Power purchase contracts included in the ARP plans are briefly summarized below:

- **Stanton A:** FMPA on behalf of the ARP has a contract for the purchase of 13 percent of the net operating capability of the Stanton A combined cycle facility from Southern Company – Florida LLC. The initial term of the purchase ends in September 2023 and includes subsequent extension options. For 2016, the ARP's purchase from Stanton A amounts to 79 MW based on the current summer rating of the facility.
- **Oleander:** FMPA on behalf of the ARP has a contract to purchase the entire capacity of, and energy generated by, Southern Power Company's Oleander Unit 5, an approximately 162 MW (summer rating) or 180 MW (winter rating), simple cycle gas turbine unit primarily fueled with natural gas and located in Brevard County. The initial term of the purchase ends in December 2027 and includes a subsequent extension option.

5.4 Summary of Current and Future ARP Resource Capacity

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

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

Line No.	Resource Description	Summer Rating (MW) 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	35	35	35	35	34	34	34	34	34	34
2	Stanton Coal Plant [2]	177	177	177	177	177	177	177	177	177	177
3	Stanton CC Unit A [2]	43	43	43	43	43	43	43	43	43	43
4	Cane Island 1-4	684	684	684	684	684	684	684	684	684	684
5	Indian River CTs [2]	82	82	82	82	82	82	82	82	82	82
6	Treasure Coast Energy Center	300	300	300	300	300	300	300	300	300	300
7	Stock Island Units	112	112	112	112	112	112	112	112	112	112
8	Sub Total Existing Resources	1,432	1,432	1,432	1,432	1,431	1,431	1,431	1,431	1,431	1,431
	Planned Resource Additions										
9	None	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,432	1,432	1,432	1,432	1,431	1,431	1,431	1,431	1,431	1,431
	Firm Capacity Import										
12	Stanton A Purchase [2]	79	79	79	79	79	79	79	79	-	-
13	Oleander Purchase	162	162	162	162	162	162	162	162	162	162
14	Peaking Purchase(s) [3]	-	-	-	-	-	-	-	-	36	58
15	Total Firm Capacity Import	241	241	241	241	241	241	241	241	198	220
16	Total Available Capacity	1,673	1,673	1,673	1,673	1,672	1,672	1,672	1,672	1,629	1,651

[1] Includes capacity from the St. Lucie Project. Amounts shown beginning 2020 have been reduced to reflect Green Cove Springs' conversion to CROD effective January 1, 2020.

[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period)

[3] Additional capacity will be required in 2024 and 2025 to maintain an 18% reserve margin during the summer season.

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

Line No.	Resource Description	Winter Rating (MW) 2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Installed Capacity										
	Existing Resources										
1	Excluded Resources (Nuclear) [1]	37	37	37	37	35	35	35	35	35	35
2	Stanton Coal Plant [2]	177	177	177	177	177	177	177	177	177	177
3	Stanton CC Unit A [2]	45	45	45	45	45	45	45	45	45	45
4	Cane Island 1-4	711	711	711	711	711	711	711	711	711	711
5	Indian River CTs [2]	99	99	99	99	99	99	99	99	99	99
6	Treasure Coast Energy Center	310	310	310	310	310	310	310	310	310	310
7	Stock Island Units	112	112	112	112	112	112	112	112	112	112
8	Sub Total Existing Resources	1,491	1,491	1,491	1,491	1,490	1,490	1,490	1,490	1,490	1,490
	Planned Resource Additions										
9	None	-	-	-	-	-	-	-	-	-	-
10	Sub Total Planned Resource Additions	-	-	-	-	-	-	-	-	-	-
11	Total Installed Capacity	1,491	1,491	1,491	1,491	1,490	1,490	1,490	1,490	1,490	1,490
	Firm Capacity Import										
12	Stanton A Purchase [2]	84	84	84	84	84	84	84	84	-	-
13	Oleander Purchase	180	180	180	180	180	180	180	180	180	180
14	Peaking Purchase(s)	-	-	-	-	-	-	-	-	-	-
15	Total Firm Capacity Import	264	264	264	264	264	264	264	264	180	180
16	Total Available Capacity	1,755	1,755	1,755	1,755	1,754	1,754	1,754	1,754	1,670	1,670

[1] Includes capacity from the St. Lucie Project. Amounts shown beginning 2020 have been reduced to reflect Green Cove Springs' conversion to CROD effective January 1, 2020.

[2] Capacities shown have been reduced to account for losses through the OUC transmission system (assumed to be 2.0% for planning period)

Schedule 5
Fuel Requirements – All-Requirements Power Supply Project

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Unit	Fuel	Actual	Forecasted									
No.	Fuel Type	Type	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Nuclear [1]		Trillion BTU	3	3	3	3	3	3	3	3	3	3	3
2	Coal		000 Ton	314	275	285	348	373	358	366	357	350	334	345
	Residual													
3		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
4		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
5		CT	000 BBL	-	-	-	-	-	-	-	-	-	-	-
6		Total	000 BBL											
	Distillate													
7		Steam	000 BBL	-	-	-	-	-	-	-	-	-	-	-
8		CC	000 BBL	-	-	-	-	-	-	-	-	-	-	-
9		CT	000 BBL	10	-	-	1	-	-	-	-	0	-	-
10		Total	000 BBL	10	-	-	1	-	-	-	-	-	-	-
	Natural Gas													
11		Steam [2]	000 MCF	992	1,026	1,066	1,299	1,396	1,339	1,366	1,333	1,308	1,247	1,291
12		CC	000 MCF	33,987	34,017	34,184	33,354	33,514	34,386	34,766	35,780	36,428	37,411	37,945
13		CT	000 MCF	377	215	202	46	57	68	196	143	206	411	308
14		Total	000 MCF	35,356	35,258.55	35,451.74	34,698.63	34,967.09	35,793.83	36,327.93	37,256.23	37,941.87	39,069.74	39,543.47
	Renewables [3]													
15		Biofuels	Billion BTU	254	246	246	246	246	246	246	246	246	246	246
16		Biomass	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
17		Geothermal	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
18		Hyrdro	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
19		Landfill Gas	Billion BTU	173	174	180	220	236	227	231	226	222	211	219
20		MSW	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
21		Solar	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
22		Wind	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
23		Other	Billion BTU	-	-	-	-	-	-	-	-	-	-	-
24		Total	Billion BTU	427	420	426	466	482	473	477	472	468	457	465
25	Other		Trillion BTU	-	-	-	-	-	-	-	-	-	-	-

[1] Nuclear generation shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.

[2] Includes natural gas used as an Igniter Fuel at the Stanton Energy Center.

[3] Includes landfill gas consumed by FMPA's ownership share of the Stanton Energy Center as a supplemental fuel source, as well as bagasse consumed by U.S. Sugar cogeneration facility in the production of power purchased by FMPA.

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		**Prime**		**Actual**	**Forecasted**									
No.	**Energy Source**	**Mover**	**Units**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
1	Annual Firm Inter-Region Interchange		GWh	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		GWh	273	269	285	285	269	286	285	269	285	286	269
3	Coal		GWh	726	711	743	918	996	952	973	947	927	879	914
	Residual													
4		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
5		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
6		CT	GWh	-	-	-	-	-	-	-	-	-	-	-
7		Total	GWh	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	GWh	-	-	-	-	-	-	-	-	-	-	-
9		CC	GWh	-	-	-	-	-	-	-	-	-	-	-
10		CT	GWh	5	-	-	0	-	-	-	-	0	-	-
11		Total	GWh	5	-	-	0	-	-	-	-	0	-	-
	Natural Gas													
12		Steam	GWh	97	98	103	127	138	132	135	131	128	122	126
	CHP Sales				(723)	(539)	(74)	(113)	(92)	(110)	(75)	(151)	(295)	(271)
	NG CC				5,169	4,796	3,287	3,058	3,420	3,433	3,758	4,049	4,552	4,687
	CHP Puchases				299	520	1,467	1,754	1,501	1,558	1,340	1,217	990	904
	Adj to Tie to LF				34	44	45	46	47	47	48	47	48	49
	Less U.S. Sugar				25	25	25	25	25	25	25	25	25	25
13		CC [2]	GWh	4,890	4,754	4,795	4,701	4,721	4,852	4,903	5,046	5,138	5,270	5,344
14		CT	GWh	34	20	18	4	5	6	18	13	19	39	30
15		Total	GWh	5,021	4,872	4,916	4,832	4,865	4,990	5,056	5,190	5,285	5,431	5,500
16	NUG		GWh	-	-	-	-	-	-	-	-	-	-	-
	Renewables [3]													
17		Biofuels	GWh	25	25	25	25	25	25	25	25	25	25	25
18		Biomass	GWh	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	GWh	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	GWh	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	GWh	17	17	17	22	23	22	23	22	22	21	21
22		MSW	GWh	-	-	-	-	-	-	-	-	-	-	-
23		Solar	GWh	-	-	-	-	-	-	-	-	-	-	-
24		Wind	GWh	-	-	-	-	-	-	-	-	-	-	-
25		Other	GWh	-	-	-	-	-	-	-	-	-	-	-
26		Total	GWh	42	41	42	46	48	47	47	47	46	45	46
27	Interchange [4]		GWh	6	-	-	-	-	-	-	-	-	-	-
28	Net Energy for Load [5]		GWh	6,072	5,894	5,987	6,082	6,177	6,274	6,361	6,452	6,544	6,641	6,729

[1] Nuclear generation shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.
[2] Includes non-firm net interchange
[3] Includes power purchased from U.S. Sugar cogeneration facility and power generated from FMPA's ownership share of the Stanton Energy Center using landfill gas.
[4] Includes firm interchange

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line		Prime		Actual	Forecasted									
No.	Energy Source	Mover	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Annual Firm Inter-Region Interchange		%	-	-	-	-	-	-	-	-	-	-	-
2	Nuclear [1]		%	4.5	4.6	4.8	4.7	4.3	4.6	4.5	4.2	4.4	4.3	4.0
3	Coal		%	12.0	12.1	12.4	15.1	16.1	15.2	15.3	14.7	14.2	13.2	13.6
	Residual													
4		Steam	%	-	-	-	-	-	-	-	-	-	-	-
5		CC	%	-	-	-	-	-	-	-	-	-	-	-
6		CT	%	-	-	-	-	-	-	-	-	-	-	-
7		Total	%	-	-	-	-	-	-	-	-	-	-	-
	Distillate													
8		Steam	%	-	-	-	-	-	-	-	-	-	-	-
9		CC	%	-	-	-	-	-	-	-	-	-	-	-
10		CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11		Total	%	0.1	-	-	0.0	-	-	-	-	0.0	-	-
	Natural Gas													
12		Steam	%	1.6	1.7	1.7	2.1	2.2	2.1	2.1	2.0	2.0	1.8	1.9
13		CC	%	80.5	80.7	80.1	77.3	76.4	77.3	77.1	78.2	78.5	79.4	79.4
14		CT	%	0.6	0.3	0.3	0.1	0.1	0.1	0.3	0.2	0.3	0.6	0.4
15		Total	%	82.7	82.7	82.1	79.5	78.8	79.5	79.5	80.4	80.8	81.8	81.7
16	NUG		%	-	-	-	-	-	-	-	-	-	-	-
	Renewables													
17		Biofuels	%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
18		Biomass	%	-	-	-	-	-	-	-	-	-	-	-
19		Geothermal	%	-	-	-	-	-	-	-	-	-	-	-
20		Hyrdro	%	-	-	-	-	-	-	-	-	-	-	-
21		Landfill Gas	%	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
22		MSW	%	-	-	-	-	-	-	-	-	-	-	-
23		Solar	%	-	-	-	-	-	-	-	-	-	-	-
24		Wind	%	-	-	-	-	-	-	-	-	-	-	-
25		Other	%	-	-	-	-	-	-	-	-	-	-	-
26		Total	%	0.7	0.7	0.7	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7
27	Interchange		%	0.1	-	-	-	-	-	-	-	-	-	-
28	Net Energy for Load		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Nuclear generation shown is the ARP Participant's Entitlement Shares in the St. Lucie Project.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Available Capacity	System Firm Summer Peak Demand [2]	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	(MW) [1]	(MW)	(MW)	QF (MW)	(MW)	(MW)	(MW)	(% of Peak)	(MW)	(MW)	(% of Peak)
2016	1,432	241	0	0	1,673	1,224	449	37%	0	449	37%
2017	1,432	241	0	0	1,673	1,242	432	35%	0	432	35%
2018	1,432	241	0	0	1,673	1,262	411	33%	0	411	33%
2019	1,432	241	0	0	1,673	1,282	391	31%	0	391	31%
2020	1,431	241	0	0	1,672	1,303	369	28%	0	369	28%
2021	1,431	241	0	0	1,672	1,321	351	27%	0	351	27%
2022	1,431	241	0	0	1,672	1,340	331	25%	0	331	25%
2023	1,431	241	0	0	1,672	1,360	312	23%	0	312	23%
2024	1,431	198	0	0	1,629	1,380	248	18%	0	248	18%
2025	1,431	220	0	0	1,651	1,399	252	18%	0	252	18%

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

[2] System Firm Summer Peak Demand includes transmission losses for the ARP Participants served through FPL, DEF, and KUA.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total	Firm	Firm		Total	System Firm Winter Peak	Reserve Margin before Maintenance			Reserve Margin after Maintenance	
Year	Installed Capacity (MW) [1]	Capacity Import (MW) [1]	Capacity Export (MW) [2]	QF (MW)	Available Capacity (MW)	Demand [2] (MW)	(MW)	(% of Peak)	Scheduled Maintenance (MW)	(MW)	(% of Peak)
2015/16	1,491	264	0	0	1,755	1,124	631	56%	0	631	56%
2016/17	1,491	264	0	0	1,755	1,146	610	53%	0	610	53%
2017/18	1,491	264	0	0	1,755	1,164	591	51%	0	591	51%
2018/19	1,491	264	0	0	1,755	1,183	572	48%	0	572	48%
2019/20	1,490	264	0	0	1,754	1,202	552	46%	0	552	46%
2020/21	1,490	264	0	0	1,754	1,219	534	44%	0	534	44%
2021/22	1,490	264	0	0	1,754	1,237	516	42%	0	516	42%
2022/23	1,490	264	0	0	1,754	1,256	498	40%	0	498	40%
2023/24	1,490	180	0	0	1,670	1,275	395	31%	0	395	31%
2024/25	1,490	180	0	0	1,670	1,292	378	29%	0	378	29%

[1] See Table 5-1 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 ARP Participants served through FPL, DEF, and KUA.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Primary	Fuel Alt.	Fuel Transport Primary	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service MM/YY	Expected Retirement MM/YY	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Resource Additions														
Changes to Existing Resources														
St. Lucie	2	St. Lucie	NP	UR	-	TK	-		1/1/2020			(2)	(2)	OT [1]

[1] Reflects capacity from Green Cove Springs' Power Entitlement Share in the St. Lucie Project, which will no longer be included in the capacity shown for the ARP upon the City's conversion to CROD effective January 1, 2020.

Section 6 Site and Facility Descriptions

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

- Cane Island Power Park –Potential Site for additional future generation.
- Treasure Coast Energy Center – Potential Site.
- Stock Island – Potential Site.

FMPA anticipates that simple cycle combustion turbines could be installed at existing generation sites located within or adjacent to the service territories of ARP Participants, such as the Stock Island site at KEYS, the Cane Island Power Park site at KUA, or the Treasure Coast Energy Center in Fort Pierce. FMPA also anticipates that combined cycle generation could be installed at the Treasure Coast Energy Center site. FMPA continuously explores the feasibility of other sites located within Florida with the expectation that ARP Participants' service territories would provide the best option for future development.

Cane Island Power Park

Cane Island Power Park is located south and west of KUA's service area and contains 683 MW (summer ratings) of gas turbine and combined cycle capacity: Units 1-3 include a simple cycle gas turbine and two combined cycle generating units, each of which is 50 percent owned by FMPA on behalf of the ARP and 50 percent owned by KUA. Cane Island Unit 4 (CI4), a nominal 300 MW (summer rating), natural gas-fired 1x1 GE 7FA combined cycle unit, is wholly owned by the ARP.

Treasure Coast Energy Center

FMPA commissioned Treasure Coast Energy Center (TCEC) Unit 1, a dual fuel low sulfur diesel and natural gas-fired 300 MW (summer rating) 1x1 GE 7FA combined cycle unit in May 2008. The Treasure Coast Energy Center is located in St. Lucie County in the City of Fort Pierce. The site was certified in June 2006 and can accommodate construction of future units beyond TCEC Unit 1, up to a total of 1,200 MW.

Stock Island

The Stock Island site currently consists of four combustion turbines, three diesel generating units, one of which is a high speed diesel that had been previously retired but refurbished and brought back into service in July of 2012. The site receives water from the Florida Keys Aqueduct Authority via a pipeline from the mainland, and also uses on-site groundwater. The site receives delivery of fuel oil to its unloading system through waterborne delivery, and also has the capability of receiving fuel oil deliveries via truck.

General

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

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

(No Proposed Generating Facilities)

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

[1] Includes AFUDC and bond issuance expenses

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

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

Note: FMPA currently has no new proposed transmission lines.

Appendix I
List of Abbreviations

Generator Type

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

Fuel Type

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

Fuel Transportation Method

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water Transportation

Status of Generating Facilities

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

Other

NA	Not Available or Not Applicable

Appendix II
ARP Participant Transmission Information

Table II-1
Planned and Proposed Transmission Additions for ARP Participants
2016 through 2027 (69 kV and Above)

City	From	To	MVA	Voltage	Circuit	Estimated In-Service Date
Kissimmee						
	Domingo Toro Substation			69 kV		6/2019
	Carl Wall	Domingo Toro		69 kV	1	6/2019
	OUC STC Central	Domingo Toro		69 kV	1	6/2019
	Osceola Parkway Substation			69 kV		6/2021
	Lake Bryan	Osceola Parkway		69 kV	1	6/2021
	Lake Cecile	Osceola Parkway		69 kV	1	6/2021
Ocala						
	Ergle Second 165 MVA Transformer		165	230/69 kV	2	6/2017