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March 25, 2005

Ms. Blanca S. Bayo, Director
Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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COMMISSION CLERK

Re: Docket No. 050145-EI; Petition for Determination of Need for St. Johns-Pellicer-Pringle 230 kV transmission line by Florida Power & Light Company

Dear Ms. Bayo:

Enclosed herewith for filing on behalf of Florida Power & Light Company ("FPL") are the following documents:

1. An original and fifteen copies of FPL's Petition to Determine Need for Electrical Transmission Line with Appendices A and B to Exhibit A to the Petition redacted; 02937-05

2. An envelope marked "Confidential" containing a copy of confidential Appendices A and B to Exhibit A of the Petition to Determine Need for Electrical Transmission Line; 02939-05

3. An original and fifteen copies of the Prefiled Direct Testimony of Vicente Ordax, Jr.; and 02940-05

4. An original and fifteen copies of FPL's Notice of Intent to Request Specified Confidential Classification. 02938-05

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Please acknowledge receipt of these documents by stamping the extra copy of this letter "filed" and returning the same to me. Thank you for your assistance with this filing.

Sincerely,

Kenneth A. Hoffman

KAH/rl
Enclosures
cc: Garson R. Knapp, Esq.

FPL\Stjohnspellicer.ltr

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need)
For St. Johns –Pellicer-Pringle 230 kV) Docket No. 050145-EI
Transmission Line by Florida Power &)
Light Company) Filed: March 25, 2005

FLORIDA POWER & LIGHT COMPANY'S
PETITION TO DETERMINE NEED FOR
<u>ELECTRICAL TRANSMISSION LINE</u>

Petitioner Florida Power & Light Company ("FPL"), by and through its undersigned counsel, hereby petitions the Florida Public Service Commission ("Commission") to determine, pursuant to Section 403.537, Florida Statutes (2002), and Rules 25-22.075 and 25-22.076, Florida Administrative Code, that there is a need for the proposed electrical transmission line described herein. In support of its Petition, FPL states:

1 The name and address of the affected agency are:

Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

2. FPL is an investor-owned electric utility that provides electric service to customers in its service area. FPL's full name and business address are:

Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

3. All pleadings, motions, notices, staff recommendations, orders and other documents filed or served in this proceeding should be served upon the following individuals on behalf of FPL:

Mr. William G. Walker, III
Vice President, Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street
Suite 800
Tallahassee, FL 32301
850/521-3900 (Telephone)
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- - and - -

Garson R. Knapp, Esq.
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420
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4. FPL proposes to construct and operate a 230kV electrical transmission line as described in Exhibit A attached hereto. The proposed transmission line would originate at FPL's existing St. Johns Substation in St. Johns County and would terminate at FPL's planned Pringle Substation in Flagler County (the "St. Johns-Pellicer-Pringle Project"). The line has a planned in-service date of December 2008.

5. The St. Johns-Pellicer-Pringle Project is subject to the Transmission Line Siting Act ("TLSA"), Sections 403.52-403.5365, Florida Statutes (2002).

6. Pursuant to the TLSA and Section 403.537, Florida Statutes (2002), and Rules 25-22.075 and 25-22.076, Florida Administrative Code, the Commission has jurisdiction to determine the need for the St. Johns-Pellicer-Pringle Project, applying the standards set forth in Section 403.537(1)(b), Florida Statutes (2002).

7. The information required to be supplied for the need determination pursuant to Rule

25-22.076, Florida Administrative Code, appears in Exhibit A hereto and is incorporated herein by reference. Fifteen (15) copies of this Petition with Exhibit A are filed herewith.

8. FPL is charged with serving both its existing customers and new customers that locate in its service territory as well as any wholesale transmission customers. Currently, FPL forecasts continued strong customer and load growth in the territory affected by the proposed St. Johns-Pellicer-Pringle Project for the foreseeable future.

9. The data and analyses contained in Exhibit A demonstrate the need for the St. Johns-Pellicer-Pringle Project in the proposed time frame as the most cost-effective alternative available, taking into account the demand for electricity, the need for electric system reliability and integrity, the need for abundant, low-cost electrical energy to assure the economic well-being of the citizens of this state, the starting and ending points of the line, and other relevant matters pursuant to Section 403.537(1)(b), Florida Statutes (2002).

10. As described in more detail in Exhibit A and the prefiled direct testimony submitted contemporaneously with this Petition, the St. Johns-Pellicer-Pringle Project is needed in December 2008 to: (a) serve the increasing load and customer base in the area south of the St. Johns Substation, north of the Pringle Substation and to the west of the existing Bunnell-St. Johns 115kV transmission line ("Project Service Area") in a reliable manner consistent with NERC and FRCC Transmission System Standards; (b) to provide additional reinforcement to the existing 115kV transmission line between the Bunnell and St. Johns Substations by providing a 230kV injection point from the planned Pellicer Substation into the Forest Grove-Matanzas 115kV line section; and (c) efficiently and effectively integrate and serve new distribution substations that are needed to serve the load growth in the Project Service Area.

11. In order to enable FPL and the Commission to comply with the notice requirements of Section 403.537(1)(a), Florida Statutes (2002) and Rule 25-22.075, Florida Administrative Code, FPL previously filed a Notice of Intent to File Petition for Transmission Line Need Determination on February 23, 2005. The Commission has set the final hearing in this docket for May 9, 2005. FPL has published notice of that hearing in the appropriate newspapers in accordance with the statutory requirements and the requirements of Rule 25-22.076(4), Florida Administrative Code.

WHEREFORE, FPL respectfully requests that the Commission:

A. Hold a hearing on this Petition in accordance with Section 403.537, Florida Statutes, Chapter 120, Florida Statutes (2002), and applicable rules of the Commission;

B. Determine that there is a need for the St. Johns-Pellicer-Pringle Project, with the starting point at FPL's existing St. Johns Substation in St. Johns County, and the ending point at FPL's planned Pellicer Substation in Flagler County together with an injection from the planned Pellicer Substation into the Forest Gove-Matanzas line section subject to the final corridor determination under the Transmission Line Siting Act; and

C. Enter a final order determining such need for the St. Johns-Pellicer-Pringle Project.

Respectfully submitted,

By: ______________________

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Rutledge, Ecenia, Purnell & Hoffman, P.A.
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- - and - -

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(561) 304-5720 (Telephone)
(561) 625-7504 (Telecopier)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Hand Delivery to the following this 25th day of March, 2005:

Martha Carter-Brown, Esq.
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

By: ______________________
KENNETH A. HOFFMAN, ESQ.

EXHIBIT "A"

(REDACTED)

FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR:

THE ST. JOHN'S-PELLICER-PRINGLE PROJECT

DOCKET NO. 050145-EI

MARCH 25, 2005

FPL

The ST. JOHNS-PELLICER-PRINGLE Project

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VIII. Attachments

1) FPL Electric Facilities Map (FPL general map)

2) Historical and Forecasted FPL peak demand

3) North Region Loads

4) Map of Study Area With Existing Facilities and Proposed Project

5a) The Transmission Planning Criteria

5b) The Transmission Planning Process

6) Distribution Planning Process and Methodology

7) Proposed Future Substations and Loads in Project Service Area

8) Map of Proposed Future Substations

9) Load Flow Project Summary Table

10) Transmission Alternative Decision Making Analysis

IX. Appendices

Appendix A - Load Flow Diagrams – With and Without project

Appendix B - Load Flow Diagrams – Alternatives

Executive Summary:

This Petition provides the background information concerning the St. Johns–Pellicer-Pringle 230kV project (SJPP Project), as well as the need for and benefits resulting from the SJPP Project. The SJPP Project meets area load requirements by serving proposed future distribution substations along the I-95/US-1 corridor while maximizing system reliability and minimizing cost to customers. The Project will primarily consist of the construction of approximately 25 miles (subject to final certification under the Transmission Line Siting Act or "TLSA") of a single circuit 230kV transmission line in Flagler and St. Johns Counties. The need for the SJPP Project is based on the following considerations:

- The need to serve the increasing load and customer base in the area south of St. Johns and north of Pringle Substations in a reliable manner consistent with North American Electric Reliability Council (NERC), Florida Reliability Coordinating Council (FRCC) and other applicable standards.
- The need to provide additional transmission reinforcement to the existing 115kV transmission line between Bunnell and St. Johns Substations.
- The opportunity, subject to final corridor siting certification under the TLSA, to efficiently and effectively integrate and serve new distribution substations that are needed to serve projected load growth within Flagler and St. Johns Counties.

Over the past five years (2000-2004), the load in the North Region[1] of FPL has grown by a Compound Annual Average Growth Rate (CAAGR) of 3.7%. FPL is forecasting the North

[1] FPL's North Region extends to the north to Nassau County and to the South to Indian River County on Florida's east coast.

Region to continue grow at a CAAGR of 3.2% over the next five years (2005-2009). Transmission assessment studies conducted by FPL during 2004 have identified regional transmission system limitations in Flagler and St. Johns Counties. These studies show that by 2008, the existing 115kV transmission network which closely parallels the coast between Bunnell and St. Johns Substations will not have sufficient capacity to provide reliable service to existing and proposed substations. Additionally, the new load that will be served by the proposed substations will be located further west of the existing 115kV coastal network.

A study of transmission alternatives has resulted in the selection of the SJPP Project as the most cost-effective and efficient means to both provide electrical service to the new load areas and substations west of the existing transmission facilities, and reinforce the existing 115kV coastal network. Current load projections (Attachment 7) and land use plans indicate that substantial new load growth will occur in Flagler and St. Johns Counties to the west of the existing 115kV transmission facilities between Pringle and St. Johns Substations. A new transmission line sited to the west of I-95 and the existing Bunnell – St. Johns 115kV transmission line would provide the most reliable, cost effective project to integrate the new substations required to serve this growing area.

In summary, the SJPP Project satisfies the need for a reliable and cost effective supply of power to FPL's existing and new customers within Flagler and St. Johns Counties.

I. Description of FPL Electrical Facilities

In order to provide an overview of FPL's existing electrical transmission system, a map of FPL's high voltage transmission network indicating the general location of generating plants, major substations, and transmission lines is shown in Attachment 1.

A listing of the history and forecast of FPL's peak demand is provided in Schedules 3.1 and 3.2 of Florida Power & Light Company's Ten Year Power Plant Site Plan (2004-2013) submitted on April 1, 2004 to the Florida Public Service Commission (the "Commission"), incorporated herein as Attachment 2. FPL's North Region extends to the north to Nassau County and to the South to Indian River County on Florida's east coast. Summer and winter historic and projected peak loads for FPL's North Region are included herein as Attachment 3.

To address these increasing demands, electric service to these new substations is required along with the appropriate transmission facilities south of St. Johns Substation, north of Pringle Substation and to the west of the existing Bunnell-St. Johns 115kV transmission line (Project Service Area). The SJPP Project best meets the needs of the Project Service Area, as described more fully in the following section.

II. The St. Johns-Pellicer-Pringle Project

The SJPP Project consists of a new 230kV transmission line extending from FPL's existing St. Johns Substation to FPL's planned Pringle Substation (scheduled to be in service by the end of 2006) and providing transmission service to the planned Pellicer Substation (scheduled to be in service by the end of 2008). In addition, the SJPP Project will provide a 230kV injection from Pellicer Substation via a 300MVA 230/115kV autotransformer into the existing 115kV coastal network by looping the Matanzas – Forest Grove 115kV line section into the Pellicer Substation. The new 25 mile (subject to final certification under the TLSA) line from St. Johns to Pringle Substations will be constructed with a single pole design on a new Right-of-Way (ROW), and will have a design and operating voltage of 230kV. The entire SJPP project will serve intermediate new distribution substations in the St. Johns and Flagler County area and will provide additional capability on the existing 115kV transmission line. This project will allow FPL to maintain reliability to all customers within the Project Service Area consistent with NERC, FRCC and other applicable standards. The proposed in-service date for the Project is December 2008.

Attachment 4 is a map showing the SJPP Project along with the existing electrical facilities in the area. The line route and future distribution substation sites are conceptual and for illustrative purposes only.

A summary of the major project components is outlined below. Construction costs include design, engineering, ROW preparation and land acquisition, in nominal or year-of-installation dollars.

SJPP Project:	**Estimated Cost**
St. Johns Substation: Site expansion & line terminal	$1.2M
Pellicer Substation: Install autotransformer	$6.4M
Estimated Transmission Line Costs (St. Johns – Pringle)	$12.6M
Estimated Transmission Line Costs	
(Loop Matanzas-Forest Grove into Pellicer)	$1.6M
Estimated Total Project Cost	$21.8M

Estimated transmission line construction costs shown in this report are based on the estimated circuit length shown. Estimated circuit lengths are based on the most direct plausible line routing between substations without regard to environmental or other constraints. Changes in line length due to constraints imposed on line routing through the certification process of the TLSA will result in variations in construction costs.

III. Transmission Planning Criteria and Process

Planning for the FPL transmission system employs practices and criteria that are consistent with the reliability standards set by the NERC and contained within the NERC Planning Standards under System Adequacy and Security, which have been adopted by the FRCC, and other applicable standards. The NERC Planning Standards are included as Attachment 5a. The NERC Planning Standards specify transmission system operating scenarios that should be evaluated, and the levels of system performance that should be attained. FPL's transmission planning process is designed to ensure compliance with the NERC and FRCC Planning Standards, and involves three major steps: (1) the preparation of system models, (2) the assessment of the transmission system, and (3) the development and evaluation of alternatives. A more detailed discussion of these steps is provided in Attachment 5b.

IV. Discussion of Need and Benefits

The need for the SJPP Project is based on the following considerations:

- The need to serve the increasing load and customer base in the Project Service Area in a reliable manner consistent with NERC Transmission System Standards.
- The need to provide additional transmission reinforcement to the existing 115kV transmission line between Bunnell and St. Johns Substations.
- The opportunity, subject to final corridor certification under the TLSA, to efficiently and effectively integrate and serve new distribution substations that are needed to serve the projected load growth in the Project Service Area.

New load development has been identified to the west of the existing 115kV coastal network between the Bunnell and St. Johns Substations which will require new electrical service within the next 2 to 7 years. Additionally the load served by the existing 115kV coastal network has grown to the point where reinforcement of the network's capability is required to maintain adequate and reliable electric service. The SJPP Project fulfills both the requirement to serve the new load areas to the west as well as the requirement to reinforce the existing 115kV network. A detailed description of these requirements follows.

A. Serve additional load

The need for this project is based largely on regional load growth. Regional load projections are developed as part of FPL's Distribution Planning Process. Attachment 6 contains a brief description of FPL's Distribution Planning process and methodology.

Future load centers in Flagler and St. Johns Counties, primarily in the I-95/US-1 corridor west of the existing 115kV transmission line, have been identified by FPL's North Area Distribution Planning Group. Attachment 7 is a table listing proposed future substations to serve these load areas including proposed in service dates and forecasted peak loadings. Attachment 8 is a map showing the substations' approximate locations, service areas and projected load densities within the service area.

The SJPP Project is needed to provide transmission service to Pellicer, Anastasia and Vermont Substations since these substations are in new load centers west of the existing 115kV transmission line.

B. Maintain system reliability

In addition to serving growing loads west of the existing 115kV network, the SJPP Project will facilitate the reinforcement of the existing 115kV transmission line between Bunnell and St. Johns Substations. The existing 115kV transmission line can be reinforced by providing a 230kV injection point from the planned Pellicer substation into the Forest Grove-Matanzas 115kV line section (Attachment 4).

1. Loadflow Results-Without the SJPP Project

Page A.1 of Appendix A provides a "Load Flow Diagram Key" to assist in interpreting the load flow maps contained in Appendices A and B. Page A.2 shows a loadflow output diagram of the 2008 winter peak load condition without the SJPP Project in-service. The diagram represents what is called the base case scenario or normal condition (i.e., no contingencies) for the year 2008/2009 winter peak load. The diagram shows that all facilities are operating within normal equipment ratings (i.e., no overloads or low voltages).

Page A.3 shows the flows without the SJPP Project in 2008 for the loss of the Bunnell – St. Joe 115kV line section of the Bunnell – St. Johns 115kV line. This results in the St. Johns – Gerona 115kV line section loading to as high as 130% of its 1300 amp thermal rating and causes low voltage conditions in the Project Service Area (See Attachment 9). This would require interruption of service to approximately 7,500 customers in 2008 to reduce loading on this line to acceptable levels.

Page A.4 shows the flows without the SJPP Project in 2008 for the loss of the St. Johns – Gerona 115kV line section of the Bunnell – St. Johns 115kV line. This results in the Bunnell – St. Joe 115kV line loading section to as high as 122% of its 1300 amp thermal rating and causes low voltage conditions in the Project Service Area (See Attachment 9). This would require interruption of service to approximately 7,100 customers in 2008 to reduce loading on this line to acceptable levels.

In addition, Pages A.5 through A.10 show overloads ranging from 108% to a high of 121% (See Attachment 9) of the thermal MVA facility rating caused by any of the following contingencies:

Bunnell 230/115kV autotransformer	(Page A.5)
St. Johns 230/115kV autotransformer	(Page A.6)
St. Johns-Deerwood 230kV line section	(Page A.7)
Tocoi-Deerwood 230kV line section	(Page A.8)
Millcreek 230/115kV autotransformer	(Page A.9)
St. Joe-Forest Grove 115kV line section	(Page A.10)

In order to mitigate the overloads and low voltages shown on Pages A.5 through A.10, it would be necessary to interrupt the service of approximately 1,000 to 8,300 customers depending on the specific outage.

2. Loadflow Results – With the SJPP Project.

Page A.11 is a loadflow output diagram showing 2008 winter peak conditions with the SJPP Project in-service. The construction of the SJPP Project provides a 230kV parallel path as well as an injection into the existing 115kV network between Bunnell and St. Johns Substations. It unloads the existing 115kV network from 140 MW to 79 MW flowing south of St. Johns Substation. It also unloads the existing 115kV network from 131MW to 69MW flowing north of Bunnell Substation. Similarly, the flows through the Bunnell and St. Johns autotransformers are reduced.

Page A.12 shows that <u>with</u> the SJPP Project in-service, the loss of the Bunnell – St. Joe 115kV line section does not result in the overloading of any transmission facility and an adequate voltage profile is maintained. This is due to the new injection of power into Matanzas – Forest Grove 115kV line section via the planned Pellicer substation.

Page A.13 shows that <u>with</u> the SJPP Project in service, the loss of the St. Johns – Gerona 115kV line section does not result in the overloading of any transmission facility and an adequate voltage profile is maintained. Again, this is due to the new injection of power into Matanzas – Forest Grove 115kV line section through the planned Pellicer substation.

Pages A.14 through A.19 show that <u>with</u> the Project in service, the same contingencies shown on Pages A.3 through A.10 (See Attachment 9) will not cause overloads or low voltage conditions at any of the transmission facilities in the Project Service Area.

C. Project Benefits

The construction of the SJPP 230kV Project provides the following benefits to the Project Service Area:

- Serves new customer load along the I-95/US-1 corridor and west of the existing 115kV transmission network from the southern portion of St. Johns County to the northern portion of Flagler County.
- Maintains area reliability by providing a parallel path to the existing Bunnell – St. Johns 115kV transmission network.
- Reduces loading on the existing Bunnell – St. Johns 115kV transmission network through the new injection at the planned Pellicer Substation.
- Reduces transmission losses by approximately 1.6MW.
- Provides a reduction of loading on the Bunnell and St. Johns autotransformers which will ultimately forestall autotransformer capacity additions at those locations.

Based on the 2004 regional load forecast, the Project Service Area's long term growth requirements will be met for at least the next 10 years.

V. Discussion of Project Alternatives

In order to meet the additional load requirements and maintain a reliable electric system for the Project Service Area, the following alternatives were considered:

A. Serve the new load with additional transmission facilities closer to the proposed future substations;

B. Serve the new load centers with an expanded distribution system using the existing 115kV transmission network; or,

C. Serve the new load by locating generation within the Project Service Area.

A. Transmission Alternatives

In order to continue to serve the load in the Project Service Area beyond December 2008 in a reliable and effective manner consistent with NERC planning standards, two transmission alternatives were investigated. The factors used to evaluate the performance of the alternatives include reliability, cost, feasibility, operational flexibility, and compatibility with long range plans. Those alternatives are discussed and assessed below. Attachment 10 includes a matrix comparing each of the transmission alternatives.

Alternative I:

This alternative consists of building a new 115kV transmission line, approximately 25 miles in length, between Pringle and St. Johns Substations. This new line would serve three additional new substations: Pellicer, Anastasia and Vermont. This alternative assumes that the new line from Bunnell to Pringle will be built at 115kV.

Page B.1 is a load flow map representing this alternative. The estimated capital cost of this alternative is $26.0M ($29.5M PVRR).

This alternative was rejected for the following reasons:

1. This alternative requires much of the existing 115kV transmission network to be rebuilt between the Bunnell and St. Johns Substations at a higher cost than the SJPP Project.
2. This alternative also requires the expansion of the St. Johns Substation to upgrade the transformation capacity, thereby increasing the cost of the alternative.
3. This alternative provides limited support to and expansion capability of the existing Bunnell-St. Johns 115kV transmission line.
4. This alternative exposes FPL customers to potential reliability concerns due to extended (multiple days) clearances during construction.

Alternative II:

This alternative consists of serving the future proposed substations from the existing 115kV transmission network. Under this alternative, the existing Bunnell – St. Johns 115kV transmission line would be providing transmission service to as many as 10 substations by 2012. In addition, significant capacitor bank additions would be required at many of the existing 115kV substations in order to provide adequate voltage support. It would also require the expansion of the St. Johns Substation in order to increase the transformation capacity (230kV to 115kV).

Page B.10 is a load flow map representing this alternative. The estimated capital cost of this alternative is $21.4M ($24.0M PVRR).

This alternative was not considered a viable option for the following reasons:

1. Serving a larger number of customers, via the additional proposed new substations, from the existing Bunnell-St. Johns 115kV transmission line could adversely impact customer reliability in the event of the outage of the transmission line.
2. The existing Bunnell – St. Johns 115kV transmission line would have to be rebuilt and extended west to provide transmission service to the proposed future substations creating a less effective transmission system with significantly less capability than a 230kV alternative within the Project Service Area.
3. This alternative provides limited operational flexibility and virtually no future expansion capability of the existing Bunnell-St. Johns 115kV transmission line.
4. This alternative exposes FPL customers to potential reliability concerns due to extended clearances during construction.

Attachment 10 shows the decision making analysis which summarizes the points of comparison of the SJPP Project and the two transmission alternatives.

B. Distribution Alternatives

The future load areas along the I-95/US-1 corridor, west of the existing Bunnell – St. Johns 115kV network will be served by new distribution substations. Based on land use plans, the long-term projected load for this area is approximately 114MVA (Pellicer, Anastasia and Vermont Substations), which represents the equivalent of fourteen 13kV feeders.

To serve this load from the existing 115kV transmission line would require a major expansion of Matanzas Substation and a minimum of two additional new distribution substations along the existing 115kV transmission network with dedicated feeders going west to the US-1 and I-95 areas. The length of feeders that would be needed from the existing transmission line area would generally be 3.5 miles longer. The additional 3.5 miles of exposure would reduce customer service reliability, would necessitate multiple crossings of US-1 and I-95, and would not be as efficient as having substations located near the load centers. The total cost of constructing the feeders, related improvements, and the appropriate transmission improvements, would be approximately $21.9 million ($24.6M PVRR). In addition, 4 new feeders out of the expanded Matanzas Substation would be required in the long-term resulting in an incremental cost of approximately $1.9M due to the additional 3.5 miles in length.

Alternatives to serving the new load centers with an expanded distribution system were not considered viable options for five major reasons:

1. The existing Bunnell – St. Johns 115kV transmission line would have to be rebuilt and extended west to provide transmission service to at least 2 proposed future substations creating a less effective transmission system with significantly less capability than a 230kV alternative within the Project Service Area.
2. Providing additional transmission capacity to the existing Matanzas Substation and providing transmission service to a minimum of 2 new distribution substations from the existing 115kV transmission line could adversely impact customer reliability in the event of the outage of the transmission line.
3. This alternative provides limited operational flexibility and virtually no future expansion capability of the existing Bunnell-St. Johns 115kV transmission line.
4. This alternative exposes FPL customers to potential reliability concerns due to extended clearances during construction.
5. Longer distribution feeder distances will provide increased feeder exposure and decreased customer service reliability and result in higher costs to FPL's customers in the long-term.

C. Generation Alternatives

Generation alternatives such as siting a new generator in the Project Service Area or building distributed generation near the new or existing substations were not considered viable options for the following reasons:

1. The need to provide transmission service to future proposed substations is not solved by adding generation in the Project Service Area.

2. Adding a new generator within the Project Service Area would require additional transmission facilities to interconnect and integrate the new generation above and beyond what is presently required by the proposed project.

Based on the reasons stated above, a generation alternative was not considered further.

VI. Adverse Consequences of Not Constructing the St. Johns-Pellicer-Pringle Project

The purpose and need for the Project is to serve the growing future loads west of the existing 115kV network in the Project Service Area and also maintain a reliable cost effective supply of power to the loads served by the existing 115kV network, in a manner that complies with NERC, FRCC and other applicable planning standards. Should the SJPP Project not be built by December of 2008, sufficient transmission capacity would not exist to serve the future and existing customers in the Project Service Area and the level of reliability would be below the level delivered to other FPL customers. The inability to serve additional loads could result in requiring the implementation of rolling outages to prevent system degradation.

Practically speaking, however, if the SJPP Project is delayed, or if the Commission denies the Petition, FPL would be forced to initiate implementation of Alternative I as shown in Attachment 10 of Exhibit "A" in order to serve the area load with an acceptable level of reliability. The result would be that FPL would be required to address its customers' needs with a less reliable, more costly alternative than the SJPP Project, and one that is not in the best long-term interest of FPL's customers than the SJPP Project.

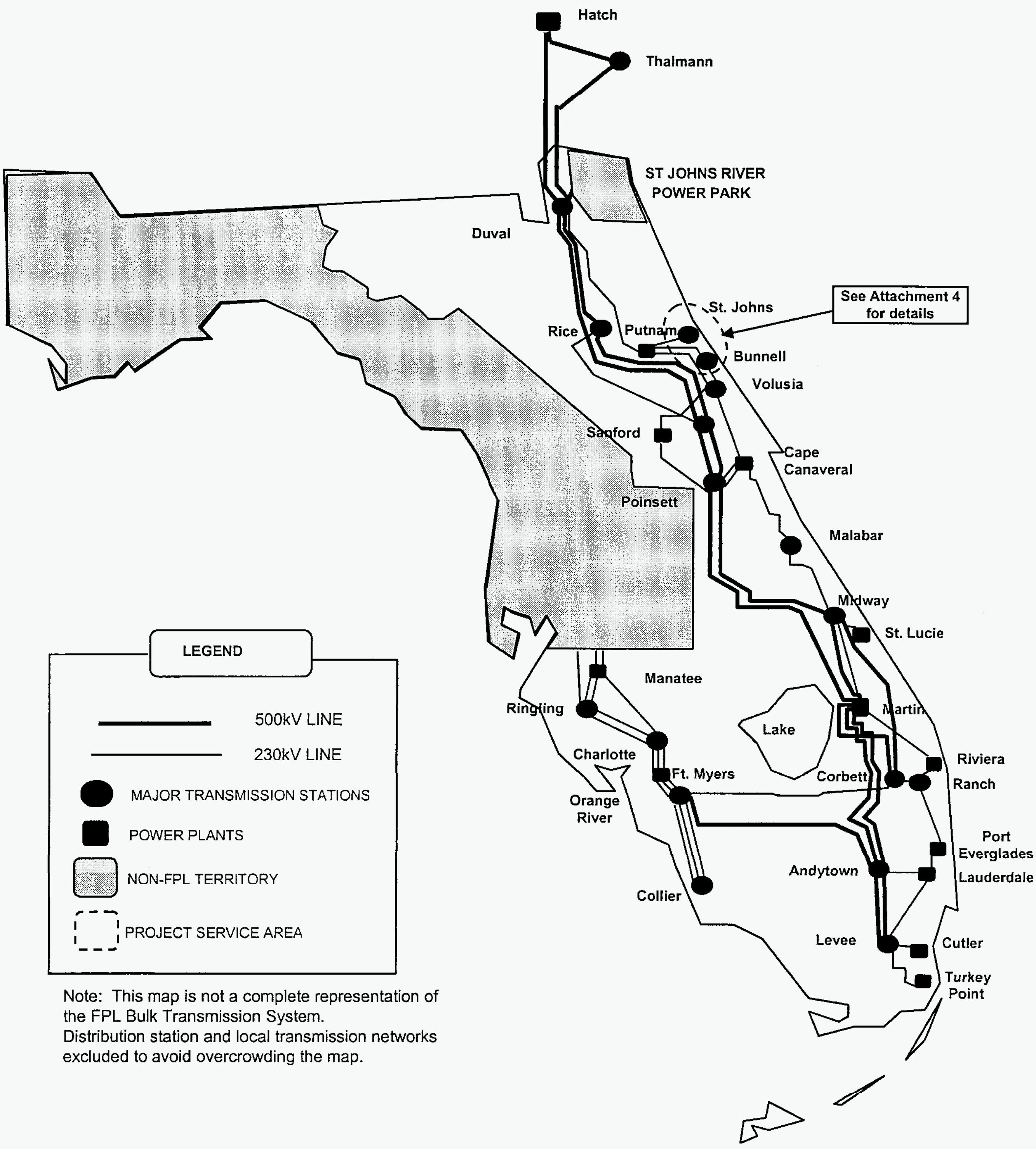
VII. Conclusion

The Project is needed by December 2008 to maintain reliable, cost-effective power supply within the Project Service Area and to serve new distribution substations. The other alternatives to address this situation do not provide for the operation of the facilities within the rated thermal and voltage limits in the event of a single contingency consistent with NERC Transmission System Standards and do not provide for the future expansion of the transmission system in the Project Service Area. The Commission, therefore, should grant FPL's Petition for a Determination of Need for the St. Johns-Pellicer-Pringle Project.

VIII. ATTACHMENTS

Attachment 1

FPL Substation and Transmission System Configuration



Note: This map is not a complete representation of the FPL Bulk Transmission System.
Distribution station and local transmission networks excluded to avoid overcrowding the map.

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	556	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,219	261	18,958	0	826	733	484	499	17,909
2003	19,668	253	19,415	0	839	775	568	535	18,261
2004	20,297	227	20,070	0	802	84	582	42	18,787
2005	20,799	230	20,569	0	809	126	592	62	19,210
2006	21,331	231	21,100	0	814	170	600	83	19,664
2007	21,851	234	21,617	0	819	214	608	103	20,107
2008	22,289	159	22,130	0	824	259	616	122	20,468
2009	22,784	159	22,625	0	828	306	622	141	20,888
2010	23,294	159	23,135	0	830	321	623	148	21,372
2011	23,783	159	23,624	0	830	321	623	148	21,861
2012	24,279	159	24,120	0	830	321	623	148	22,357
2013	24,784	159	24,625	0	830	321	623	148	22,862

Historical Values (1994 - 2003):

Col. (2) - Col.(4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) -Col. (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business on Call (BOC) and Commercial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2004 - 2013):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2003 are incorporated into the forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2003 starting point.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15.167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	457	242	16,060
2002/03	20,190	246	19,944	0	1,116	581	453	288	18,621
2003/04	14,752	211	14,541	0	938	601	534	309	13,280
2004/05	20,583	208	20,375	0	939	114	540	22	18,968
2005/06	21,100	209	20,891	0	946	149	546	29	19,430
2006/07	21,605	212	21,393	0	952	183	551	37	19,882
2007/08	22,046	137	21,909	0	958	218	556	44	20,270
2008/09	22,539	137	22,402	0	964	252	561	51	20.712
2009/10	23,026	137	22,889	0	968	284	564	57	21,153
2010/11	23,522	137	23,385	0	968	284	564	57	21,649
2011/12	24,024	137	23,887	0	968	284	564	57	22,151
2012/13	24,535	137	24,398	0	968	284	564	57	22,663
2013/14	25,057	137	24,920	0	968	284	564	57	23,184

Historical Values (1994/95 - 2003/04):

Col. (2) - Col.(4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business on Call (BOC) and Commercial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2004/05- 2013/14):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2003 are incorporated into the forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and are based on projections with a 1/2003 starting point.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

ATTACHMENT 3

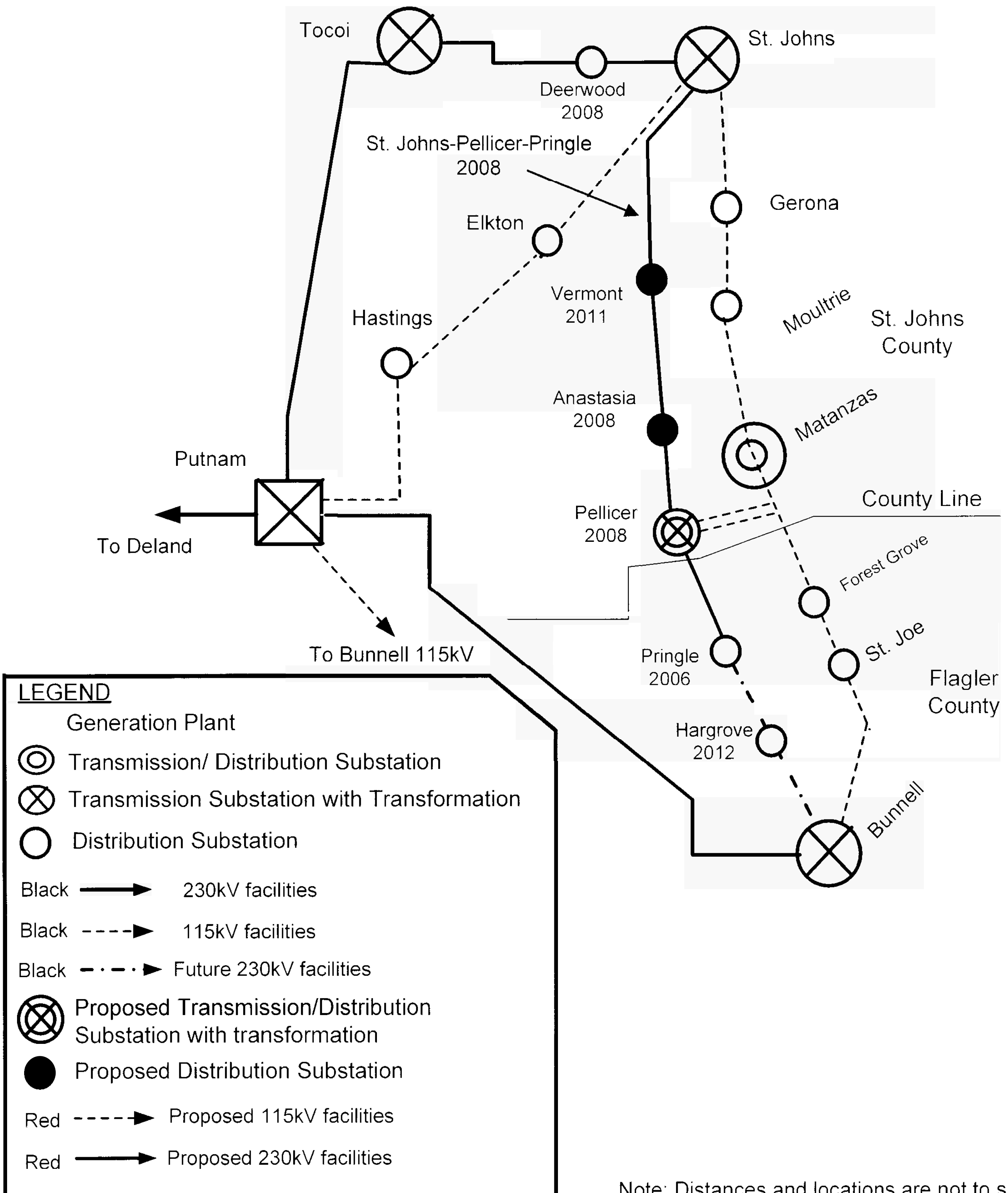
FPL North Region

Historical and Forecasted Peak Loads (MW)

Year	North Region FPL Winter	North Region FPL Summer
1999	2765	2766
2000	2786	2869
2001	2977	2916
2002	3217	2981
2003	3656	3105
2004	2725	3316
2005	3925	3402
2006	4041	3515
2007	4175	3635
2008	4314	3760
2009	4446	3890
2010	4576	4026
2011	4712	4169
2012	4847	4317
2013	4986	4470

ATTACHMENT 4

ST. JOHNS - PELLICER - PRINGLE (SJPP)



Note: Distances and locations are not to scale

ATTACHMENT 5a

The Transmission Planning Criteria

The NERC Transmission System Standards are divided into categories A, B, C and D. FPL utilizes these Standards for its planning criteria. Category A addresses normal system conditions with all facilities in service. Category B addresses system conditions following the loss of a single facility. Category C addresses system conditions following the loss of two or more facilities. Finally, Category D addresses system conditions following an extreme event where multiple facilities are removed from service.

The need for transmission system upgrades is most frequently based on potential overload conditions associated with the Category B contingencies (single contingency) listed in Table 1 of this Attachment 5a. Generally, Category C and D multiple contingency analysis is used to identify potential situations of cascading interruptions and/or instability.

The planned transmission system with its expected loads and transfers must be stable and within applicable ratings for all Category A, B, and C contingency scenarios.

The effect of Category D contingencies on system stability are also evaluated. The design of new transmission connections should take into account and minimize, to the extent practical, the adverse consequences of Category D contingencies. Lower probability Category D contingencies, when they occur in combination with forecasted demand levels and firm interchange transactions, must not result in uncontrolled, cascading interruptions. While controlled interruption of load and/or opening of transmission circuits may be needed, the system should be within its emergency limits and capable of rapid restoration after operation of automatic controls.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001.

ATTACHMENT 5a

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) for an event or condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility therma ating or system voltage limit as determined and consistently applied by the system or facility established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Categories A and B - Approved by Planning Committee February 27, 2001, and NERC Board of Trustees June 12, 2001.
Category C - Approved by Planning Committee November 15, 2001, the Market Interface Committee January 10, 2002, and NERC Board of Trustees February 20, 2002.
Category D - Approved by Planning Committee September 27, 2001, and NERC Board of Trustees October 16. 2001

ATTACHMENT 5b

The Transmission Planning Process

Step 1: Preparation of System Models

To prepare system models[1], regional load profiles must be developed for the current year and for representative years of the ten-year planning horizon. These profiles incorporate the most recent substation load information available. Thus, the distribution planning groups in each region are asked to provide Transmission Planning with historical and projected substation loads and future distribution substation data.

Once the load profiles have been developed, they are used as input into the load flow, fault analysis and stability programs, which simulate and study the behavior of the transmission system. Other major inputs into these programs are the generation dispatch and the base transmission system representation including expected line and equipment performance data. Firm long-term transmission service obligations are incorporated into the programs. The base transmission system representation incorporates existing and planned facilities. In addition, appropriate operating criteria involving voltage limits, generator reactive limits, and transformer taps are observed. All major utilities to which FPL is interconnected are also represented.

Step 2: Transmission System Assessment

Using the system models developed in Step 1, outage contingencies are simulated using load flow and stability programs. These outage contingencies consist of two types as discussed in

[1] The models used for this analysis are the Florida Reliability Coordinating Council's year 2004 summer and winter load flow databank cases modeling expected system conditions in year 2008 and 2009. These models are run on Power Technologies Incorporated (PTI) load flow programs which are commonly used and accepted in the electric industry.

Attachment 5a: (1) single events with a higher probability of occurrence such as the loss of one transmission line section or autotransformer and (2) multiple events such as the loss of all transmission lines in a common transmission ROW. Generally, the latter event has a lower probability of occurrence but can result in consequences that are more severe. All single and credible multiple contingencies are analyzed. For each of these contingencies, the response of the power system is analyzed and violations of the planning criteria are evaluated.

Step 3: Development and Evaluation of Alternatives

This step addresses potential criteria violations. First, switching techniques and other operational procedures are tested to determine if such actions resolve the problems. If satisfactory operational procedures cannot be implemented, several alternatives for transmission system reinforcements are developed. Cost estimates for the viable alternatives are then determined. Subsequently these alternatives are evaluated (See Attachment 10). After evaluating the transmission system project alternatives, the project that best meets the requirements and other considerations is selected.

Attachment 6

The Distribution Planning Process and Methodology

Step 1: Distribution Forecast

Historically, the long-term growth in peak load demand has been largely a function of population growth. Annual summer and winter peak demands are forecast by an analysis of both FPL system-wide summer and winter peak forecasts and a separate forecast for each of the five FPL regions. The system-wide summer and winter peak forecast takes into consideration the forecasted number of FPL customers (derived from population projections produced by the University of Florida's population forecast).

FPL's North Area Distribution Planning Group is responsible for forecasting regional substation loads for the distribution system for fourteen North Florida counties, including Flagler and St. Johns. Based on historical load demand at each substation, customers' requests for service, expected major real-estate developments, and other customer-driven variables, a specific load forecast down to the individual substation is developed.

Step2: Distribution System Assessment

The North Area Distribution Planning Group uses up-to-date proposed land-use plans for the appropriate counties. Planning and zoning maps developed by respective county planning departments provide the residential dwelling, commercial, industrial and agricultural units per acre requirements for various land densities (e.g. Rural, Estates, etc.). The land density is translated to load density using field measurement data as to average connected kVA per dwelling unit. Load projections are developed for a 10 year horizon. New substation sites are identified to relieve existing substations the year when their respective capacity is projected to be exceeded. Determination of the ultimate substation service area is then made according to load density requirements, geographical restrictions and maximum substation capacity.

Step 3: Development and Evaluation of Alternatives

Once a new substation site has been determined to be needed in an area, a cross-functional team of employees representing land acquisition, environmental, transmission engineering, transmission planning, and distribution planning is formed to evaluate properties for possible purchase. Cost estimates for viable alternatives are then determined. Finally, a decision for purchase is made after considering all pertinent factors.

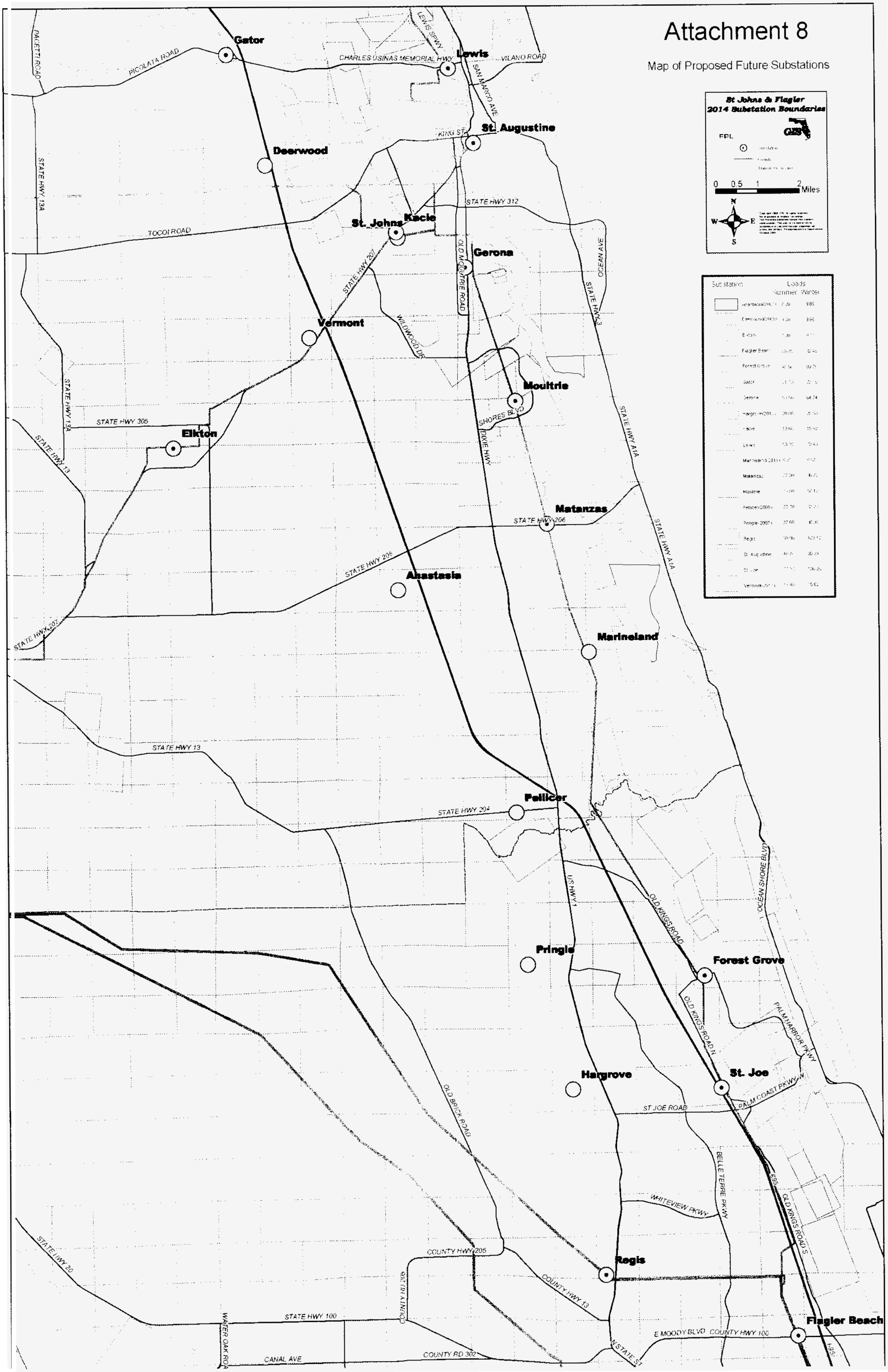
Attachment 7

PROPOSED FUTURE SUBSTATIONS AND LOADS IN PROJECT SERVICE AREA

In-service	Substation	County Area	Long Term Load (MVA)
2006	Pringle	Flagler	74
2008	Pellicer	St. Johns	49
2008	Anastasia	St. Johns	42
2008	Deerwood	St. Johns	24
2011	Vermont	St. Johns	23
2012	Hargrove	Flagler	80

Attachment 8

Map of Proposed Future Substations



ATTACHMENT 9

Load Flow Project Summary Table

Whithin Limits = Blue font		Without SJ-P-P Project		With SJ-P-P Project		With Alternative 1		With Alternative 2	
Outside Limits = Red font	Line overloaded/Substation	Overload	Low Voltage	Overload	Low Voltage	Overload	Low Voltage	Overload	Low Voltage
Contingency		(%)	(P.U.)	(%)	(P.U.)	(%)	(P.U.)	(%)	(P.U.)
Bunnell - St. Joe 115kV	Hastings - Elkton 115kV	113	-	49	-	25	-	29	-
	St. Johns autotransformer #1	107	-	55	-	39	-	41	-
	St. Johns autotransformer #2	n/a	-	n/a	-	37	-	38	-
	St. Johns - Gerona 115kV	130	-	37	-	68	-	73	-
	Moultrie - Gerona 115kV	122	-	19	-	68	-	58	-
	Matanzas 115kV	-	0.84	-	1.00	-	1.00	-	1.00
	St. Johns 115kV	-	0.91	-	1.00	-	1.00	-	1.00
	St. Joe 115kV	-	0.73	-	0.98	-	1.00	-	0.99
	St. Johns 230kV	-	0.92	-	0.97	-	0.97	-	0.97
	Moultrie 115kV	-	0.85	-	1.00	-	1.00	-	1.00
	Elkton 115kV	-	0.92	-	1.00	-	1.00	-	1.00
	Gerona 115kV	-	0.88	-	0.99	-	1.00	-	1.00
	Forest Grove 115kV	-	0.74	-	0.99	-	1.00	-	1.00
	Gator 115kV	-	0.92	-	1.00	-	1.01	-	1.01
	Anastasia 115kV	-	0.82	-	n/a	-	1.01	-	1.00
	Anastasia 230kV	-	n/a	-	0.97	-	n/a	-	n/a
	Deerwood 230kV	-	0.93	-	0.98	-	0.98	-	0.98
	Pellicer 115kV	-	0.76	-	1.00	-	1.01	-	0.99
	Pellicer 230kV	-	n/a	-	0.97	-	n/a	-	n/a
St. Johns - Gerona 115kV	Bunnell - St. Joe 115kV	122	-	35	-	68	-	73	-
	St. Joe - Forest Grove 115kV	102	-	4	-	81	-	76	-
	Bunnell 230kV	-	0.95	-	0.98	-	0.98	-	0.98
	Matanzas 115kV	-	0.83	-	1.00	-	1.01	-	0.99
	St. Joe 115kV	-	0.91	-	1.00	-	1.00	-	1.00
	Moultrie 115kV	-	0.82	-	0.99	-	1.01	-	0.99
	Gerona 115kV	-	0.82	-	0.99	-	1.01	-	0.99
	Forest Grove 115kV	-	0.90	-	1.00	-	1.00	-	1.00
	Anastasia 115kV	-	0.84	-	n/a	-	1.01	-	0.99
	Anastasia 230kV	-	n/a	-	0.98	-	n/a	-	n/a
	Pellicer 115kV	-	0.87	-	1.01	-	1.01	-	0.99
	Pellicer 230kV	-	n/a	-	0.97	-	n/a	-	n/a
Bunnell autotransformer	Bunnell 115kV	-	0.95	-	0.98	-	0.99	-	1.01
	St. Joe 115kV	-	0.94	-	0.99	-	0.99	-	1.00
	Forest Grove 115kV	-	0.94	-	0.99	-	1.00	-	1.00
	Pellicer 115kV	-	0.95	-	1.01	-	0.99	-	1.00
	Pellicer 230kV	-	n/a	-	0.98	-	n/a	-	n/a
St. Johns autotransformer	Hastings - Elkton 115kV	108	-	77	-	16	-	14	-
	Millcreek autotransformer #1	102	-	79	-	29	-	27	-
	Millcreek autotransformer #2	n/a	-	n/a	-	25	-	24	-
	St. Johns 115kV	-	0.94	-	0.97	-	1.01	-	1.01
	Moultrie 115kV	-	0.94	-	0.98	-	1.01	-	1.01
	Gerona 115kV	-	0.94	-	0.97	-	1.01	-	1.01
St. Johns - Deerwood 230kV	Hastings - Elkton 115kV	108	-	67	-	39	-	39	-
	Millcreek autotransformer #1	102	-	83	-	44	-	43	-
	Millcreek autotransformer #2	n/a	-	n/a	-	39	-	39	-
	St. Johns 115kV	-	0.94	-	0.98	-	1.00	-	0.99
	St. Johns 230kV	-	0.90	-	0.95	-	0.96	-	0.96
	Moultrie 115kV	-	0.94	-	0.98	-	1.00	-	1.00
	Gerona 115kV	-	0.94	-	0.98	-	1.00	-	1.00
Tocoi - Deerwood 230kV	Hastings - Elkton 115kV	111	-	68	-	40	-	40	-
	Millcreek autotransformer #1	104	-	84	-	45	-	44	-
	Millcreek autotransformer #2	n/a	-	n/a	-	40	-	39	-
	Matanzas 115kV	-	0.95	-	0.98	-	1.00	-	1.00
	St. Johns 115kV	-	0.94	-	0.97	-	1.00	-	1.00
	St. Johns 230kV	-	0.89	-	0.95	-	0.96	-	0.96
	Moultrie 115kV	-	0.94	-	0.98	-	1.00	-	1.00
	Gerona 115kV	-	0.94	-	0.97	-	1.00	-	1.00
	Deerwood 230kV	-	0.89	-	0.95	-	0.96	-	0.96
Millcreek autotransformer	St. Johns autotransformer #1	121	-	93	-	35	-	32	-
	St. Johns autotransformer #2	n/a	-	n/a	-	33	-	31	-
			0.95	-					
St. Joe - Forest Grove 115kV	Forest Grove 115kV		0.94	-	1.01	-	1.00	-	0.99
	Pellicer 115kV		0.95	-	1.02	-	1.01	-	0.99
	Pellicer 230kV		n/a	-	0.98	-	n/a		n/a

ATTACHMENT 10

TRANSMISSION ALTERNATIVE DECISION MAKING ANALYSIS

DECISION STATEMENT		Provide adequate and reliable service to the Bunnell - St. Johns area.								
		ALTERNATIVES:								
		I/S YEAR		Alternative I	I/S YEAR		Alternative II	I/S YEAR		SJPP PROJECT
OBJECTIVES		2008		Build a new St. Johns - Pellicer - Pringle 115kV transmission line (1495 amps). Install a new 300 MVA 230/115kV autotransformer at St. Johns. Re-conduct Bunnell - St. Joe 115kV line section from 1115 amps to 1905 amps. Re-conduct St. Johns - Gerona 115kV line section from 1115 amps to 1905 amps. Re-conduct Moultrie - Gerona 115kV line section from 1115 amps to 1495 amps. Re-conductor Hastings - Elkton 115kV line section from 365 amps to 750 amps. Install a new 300 MVA 230/115kV autotransformer at Millcreek. Install 110 Mvars between Bunnell and St. Johns.	2008		Grove 115kV line section. Install a new 300 MVA 230/115kV autotransformer at Bunnell. Re-conductor Bunnell - St. Joe 115kV line section from 1300 amps to 1905 amps. Re-conductor Hastings - Elkton 115kV line section from 365 amps to 750 amps. Upgrade Matanzas - Moultrie 115kV line section from 1115 amps to 1300 amps. Install a new 300 MVA 230/115kV autotransformer at St. Johns. Re-conductor St. Johns - Gerona 115kV line section from 1300 amps to 1905 amps. Upgrade St. Joe - Forest Grove 115kV line section from 1115 amps to 1300 amps. Re-conductor Moultrie - Gerona 115kV line section from 1115 amps to 1905 amps. Install a new 300 MVA 230/115kV autotransformer at Millcreek. Install 110 Mvars between Bunnell and St. Johns.			transmission line (1905 amps). Install a new 300 MVA 230/115kV autotransformer at Pellicer. Loop Matanzas - Forest Grove 115kV line section into Pellicer.
REQUIREMENTS		Yes	No	Information	Yes	No	Information	Yes	No	Information
Alternative must provide for reliable service to area customers		X				X		X		
Alternative Plan is feasible to construct		X			X			X		
DESIRES	VL	Score	VL*S	Information	Score	VL*S	Information	Score	VL*S	Information
Minimize Price (Present value of revenue requirements)	10.0	7	70	PVRR $29.5M	10	100	PVRR $24.0M	10	100	PVRR $24.0M
Maximize reliability of service to customers	9.2	8	74	Mitigates single contingency overloads in the mid term.	3	28	Mitigates single contingency overloads in the near term.	10	92	Mitigates single contingency overloads for an extended amount of time.
Maximize compatibility with Long range plans	6.1	7	43	Allows for additional load growth.	1	6	Allows for minor additional growth.	10	61	It allows for future load growth and service to new stations.
Provides operational flexibility	5.3	7	37	Acceptable operational flexibility.	2	11	Limited operational flexibility.	10	53	Provides maximum operational flexibility.
Minimize construction difficulties	4.9	7	34	Requires extended line and bus clearances.	4	20	Requires extended line and bus clearances.	10	49	Requires minimum line and bus clearances.
TOTAL VALUE SCORE			258			164			355	** PREFERED ALTERNATIVE **

VL = Weighted Value

EXHIBIT "A"
(REDACTED)

Appendices A & B

FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR:

THE ST. JOHN'S-PELLICER-PRINGLE PROJECT

DOCKET NO. 050145-EI

MARCH 25, 2005

FPL

APPENDIX A

Load Flow Diagrams – With and Without Project

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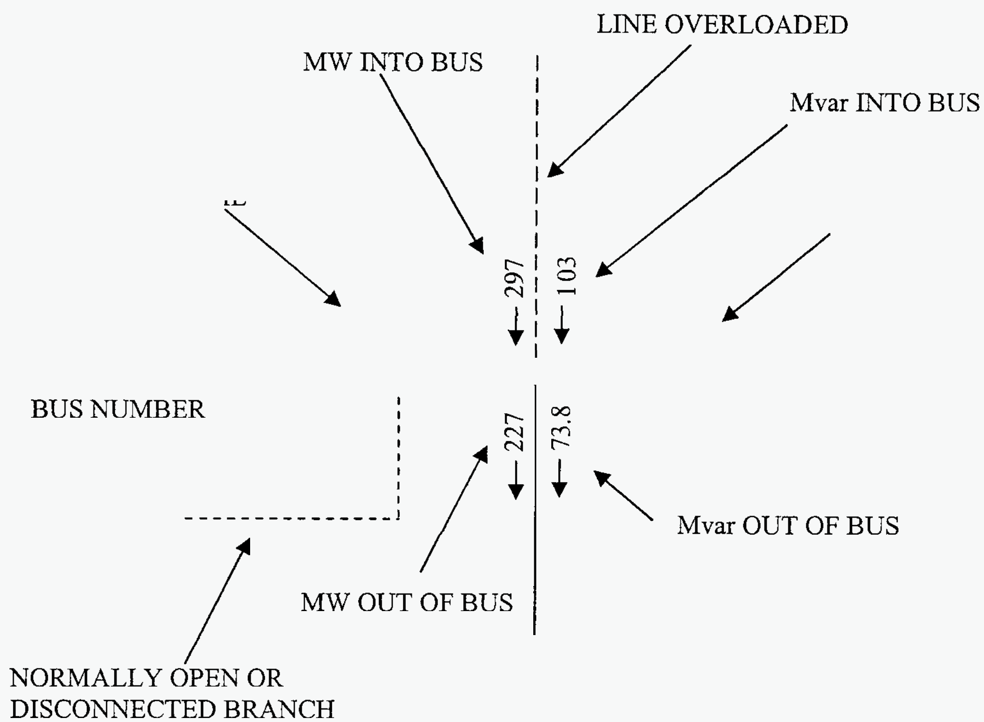
Load Flow Diagram Key



PAGES A.2 – A.19 REDACTED

APPENDIX B

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PAGES B.1 – B.18 REDACTED