REDACTED

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI
FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

MINIMUM FILING REQUIREMENTS
2013 TEST YEAR

VOLUME 7 OF 7
SECTION F: MISCELLANEOUS SCHEDULES
MFR F-3 TO F-9

COM
APA 1
ECR 17
GCL 1
RAD 1
SRC 1
ADM
OPC
CLK

F 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: Provide a copy of the "Business Contracts with Officers, Directors and Affiliates" schedule included in the company's most recently filed Annual Report as required by Rule 25-6.135, Florida Administrative Code. Provide any subsequent changes affecting the test year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
_X_ Historical Test Year Ended 12/31/11

Witness: Kathleen Slattery

Line No.	(1) Name of Officer or Director	(2) Name and Address of Affiliated Entity	(3) Relationship With Affiliated Entity	(4) Amount of Contract or Transaction	(5) Description of Product or Service
1					
2					
3	NONE				
4					
5					
6					
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: Supply a copy of all NRC safety citations issued against the company within the last two years, a listing of corrective actions and a listing of any outstanding deficiencies. For each citation provide the dollar amount of any fines or penalties assessed against the company and account(s) each are recorded.

Type of Data Shown:
____ Projected Test Year Ended ___/___/___
____ Prior Year Ended ___/___/___
_X_ Historical Test Year Ended 12/31/11
Witness: J. A. Stall

Line No. (1)

A NRC Notice of Violation (NOV) is a formal written citation in accordance with the Code of Federal Regulations that sets forth one or more violations of a legally binding regulatory requirement. The NOV states the alleged violation and may require a licensee to submit a written explanation or statement in reply if the NRC believes that the licensee has not already addressed all the issues contained in the NOV. FPL does not necessarily concur with all of the NRC's findings in the NOV's discussed in this MFR. As described below, FPL has implemented corrective actions in connection with each NOV discussed in this MFR. Further, there are no outstanding deficiencies associated with any of the NOV's described below.

In 2010 - 2011, FPL received the following Notice of Violation (NOV) relating to the St. Lucie Nuclear Plant

• Violation associated with a Yellow Significance Determination Process finding, no civil penalty, issued on April 19, 2010, related to an October 2008 component cooling water (CCW) air intrusion event. Attachment 1 is the NOV. Corrective actions: Implementation of a design change; improved procedural guidance for immediate operability determinations; improved procedural guidance to screen and classify condition reports based on risk significance; improved procedures for responding to air intrusion events for CCW; training on procedural improvements.

In 2010 - 2011, FPL received the following Notice of Violation (NOV) relating to the Turkey Point Nuclear Plant

• Violation associated with a White Significance Determination Process finding, no civil penalty, issued February 7, 2011, related to an uncontrolled document containing Safeguards Information (SGI). Attachment 2 is the NOV. Corrective actions: Request to NRC for revised SGI distribution; revised SGI procedure to provide additional guidance upon receipt of external SGI documents; implementation of a desktop instruction guide for executive administrative assistants; revised process to incorporate guidance regarding receipt of incoming NRC correspondence.

• Violation associated with a White Significance Determination Process finding, and Severity Level III violation, $ 70,000 civil penalty, issued on June 21, 2010, related to regulatory compliance issues with the Unit 3 spent fuel storage racks. The penalty was charged to FERC account 426.300 - Penalties (customers were not charged for civil penalty). Attachment 3 is the NOV. Corrective actions: Development and implementation of a comprehensive plan for maintaining the spent fuel racks; improved procedural guidance for operability and reportability reviews; training on procedural improvements.

• Violation associated with a Green Significance Determination Process finding, no civil penalty, issued June 28, 2011, for failure to conduct a physical inventory of all special nuclear material. Attachment 4 is the NOV. Corrective Actions: Conducted annual inventory; development and implementation of a desktop instruction to track and resolve items identified through NRC inspections.

In 2010 - 2011, FPL received the following Notice of Violation (NOV) relating to the Turkey Point Nuclear Plant, Units 6 and 7

• Two Severity Level IV violations, no civil penalty, issued April 4, 2011, for failure to adequately implement aspects of the Part 21 program and the corrective action program in accordance with Appendix B to 10 CFR Part 50. Attachment 5 is the NOV.

Supporting Schedules: Recap Schedules:

ATTACHMENT 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

April 19, 2010

EA-09-321

Mr. Mano Nazar
Executive Vice President and
Chief Nuclear Officer
Florida Power & Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF A YELLOW FINDING AND NOTICE OF VIOLATION (NRC COMPONENT DESIGN BASES INSPECTION REPORT 05000335/2010007 AND 05000389/2010007), ST. LUCIE NUCLEAR PLANT

Dear Mr. Nazar:

The purpose of this letter is to provide you with the disposition and final significance determination of the two preliminary Greater than Green findings discussed in NRC Inspection Report No. 05000335/2009006 and 05000389/2009006, dated January 19, 2010, (ML100210081). The two preliminary findings were related to air intrusion into the Component Cooling Water (CCW) system that occurred in October 2008, and involved (1) the failure of a non-safety system that could result in a common cause failure of both trains of the CCW system, contrary to 10 CFR 50 Appendix B, Criterion III, "Design Control", and (2) the failure to identify and correct a condition adverse to quality involving the source of the air in-leakage into the CCW system, contrary to 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action". The NRC's Inspection Report identified two apparent violations corresponding to the two preliminary findings.

At your request, a Regulatory Conference was held on February 19, 2010, to discuss your views on these issues. During the conference, your staff described the circumstances surrounding the October 2008 event, Florida Power and Light Company's (FPL's) assessment of the significance of the two preliminary findings, its root cause evaluation, and the corrective actions taken. FPL highlighted several differences between its risk assessment and the NRC's preliminary risk assessment as documented in our inspection report of January 19, 2010. At the conference, FPL contested the preliminary finding and apparent violation involving 10 CFR 50, Appendix B, Criterion III. In summary, FPL concluded that when St. Lucie Unit 1 was licensed, the facility was not required to incorporate a single failure design capability for a non-safety system. As such, FPL concluded that a violation of 10 CFR 50, Appendix B, Criterion III, did not occur. Regarding the second preliminary finding involving the failure to identify and correct the source of air in-leakage into the CCW system, FPL concluded that the significance of the finding should be characterized as Green. FPL did not contest the validity of the corresponding 10 CFR 50 Appendix B, Criterion XVI violation.

Regarding the preliminary finding involving 10 CFR 50, Appendix B, Criterion III, the NRC considered the information provided by FPL at the conference, and reviewed available information to determine the applicability of design control regulations to St. Lucie Unit 1. This included a review of the requirements at the time St. Lucie Unit 1 was originally licensed, the Safety Evaluation Report issued by the NRC following the review of St. Lucie Unit 1 design, the Final Safety Analysis Report, and the single failure analysis associated with the CCW system. Based on the review, the NRC determined that the Unit 1 CCW system met the design requirements at the time of licensing and at the time of the October 2008 air intrusion event. Therefore, this issue does not represent a performance deficiency, and accordingly, a violation of 10 CFR 50, Appendix B, Criterion III did not occur. Accordingly, Apparent Violation 05000335, 389/2009006-05, "Failure to Translate Design Basis Specifications to Prevent Single Failure of CCW" is considered closed.

After considering the information developed during the inspection and information provided by FPL during and after the conference, the NRC has concluded that the finding involving the failure to identify and correct the source of the air in-leakage into the CCW system is characterized as Yellow, i.e., a finding of substantial significance with regard to safety, which will require additional NRC inspections. The bases for the NRC's significance determination of this finding, and the differences in the licensee's characterization of the findings, are discussed in Enclosure 2.

You have 30 calendar days from the date of this letter to appeal the staff's significance determination for the Yellow finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 2.

The NRC also has determined that the failure to identify and correct the source of the air in-leakage into the CCW system is a violation of 10 CFR 50 Appendix B, Criterion XVI, as cited in the enclosed Notice of Violation (Notice). The circumstances surrounding the violation were described in detail in NRC Inspection Report No. 05000335/2009006 and 05000389/2009006, dated January 19, 2010 (ML100210081). In accordance with the NRC Enforcement Policy, the Notice is considered escalated enforcement action because it is associated with a Yellow finding.

For administrative purposes, this letter is issued as a separate NRC Inspection Report, No. 05000335/2010007 and 05000389/2010007. Apparent Violation 05000335, 389/2009006-06, related to the CCW air intrusion event, is now Violation 05000335/2009006-06, "Failure to Identify and Correct a Condition Adverse to Quality." This violation was determined to have a cross-cutting aspect in the area of Human Performance, Decision Making, specifically H.1(a).

Because plant performance for this issue has been determined to be beyond the licensee response band of the NRC Action Matrix, we will use the Action Matrix to determine the most appropriate NRC response for this event. We will notify you, by separate correspondence, of that determination.

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence and the date when full compliance will be achieved is already adequately addressed on the docket in the "St. Lucie

Meeting Summary," dated February 26, 2010 (ML100601170). Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, please follow the instructions specified in the Notice of Violation, Enclosure 1.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, Enclosures 1 and 2, and your response, if any, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response, if any, should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such information, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). The NRC also includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/).

Sincerely,

/RA/

Luis A. Reyes
Regional Administrator

Docket Nos.: 50-335, 50-389
License Nos.: DPR-67 and NPF-16

Enclosures: 1. Notice of Violation
2. NRC Bases for Final Significance Determination

cc w/encls: (See page 4)

to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, please follow the instructions specified in the Notice of Violation, Enclosure 1.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, Enclosures 1 and 2, and your response, if any, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response, if any, should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such information, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). The NRC also includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/).

Sincerely,

/RA/

Luis A. Reyes
Regional Administrator

Docket Nos.: 50-335, 50-389
License Nos.: DPR-67 and NPF-16

Enclosures: 1. Notice of Violation
2. NRC Bases for Final Significance Determination

cc w/encls: (See page 4)

X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: ☐ Yes ACCESSION NUMBER:________________ ☐ SUNSI REVIEW COMPLETE

OFFICE	RII:ORA	RII:DRS	RII:DRS	RII:DRS	RII:DRP	RII:DRS	RII:ORA
SIGNATURE	RA	RA	RA	VIA EMAIL	RA	RA	RA
NAME	CEvans	WRogers	BDesai	KKennedy	LWert	JLubinski	VMcCree
DATE	4/7/2010	4/5/2010	3/31/2010	4/14/2010	4/14/20104/	4/13/20104/	4/15/2010
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
OFFICE	OE	NRR					
SIGNATURE	email	Email					
NAME	RZimmerman	MCUNNINGHAM					
DATE	4/14/2010	4/8/2010	4/ /2010	4/ /2010	4/ /2010	4/ /2010	4/ /2010
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: S:\ORA\ST LUCIE FINAL SIG LETTER (EA-09-321) REV3 (2).DOC

cc w/encl:
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St. Lucie Nuclear Plant
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Plant General Manager
St. Lucie Nuclear Plant
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Letter to Mano Nazar from Luis A. Reyes dated April xx, 2010

SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A YELLOW FINDING AND NOTICE OF VIOLATION (NRC COMPONENT DESIGN BASES INSPECTION REPORT 05000335/2010007 AND 05000389/2010007), ST. LUCIE NUCLEAR PLANT

Distribution w/encls:
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S. Sparks, RII

NOTICE OF VIOLATION

Florida Power and Light	Docket No. 50-335
St. Lucie Nuclear Plant	DPR-67
Unit 1	EA-09-321

During an inspection completed by the NRC on December 10, 2009, a violation of NRC requirements was identified. The circumstances surrounding the violation were described in detail in NRC Inspection Report No. 05000335/2009006 and 05000389/2009006, dated January 19, 2010 (ML100210081). In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," states that measures shall be established to assure that conditions adverse to quality, such as deficiencies, deviations, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.
>
> Contrary to the above, the licensee failed to identify and correct a significant condition adverse to quality affecting the Component Cooling Water (CCW) system. Specifically, in October 2008, air intrusion from the containment instrument air (IA) system into the CCW system occurred which affected both redundant trains of the CCW system. The troubleshooting and subsequent corrective actions that were implemented by the licensee failed to identify the source of the air in-leakage and ensure that the CCW system remained capable of delivering adequate cooling to essential equipment used to mitigate design bases accidents. In addition, the corrective actions failed to preclude a similar air intrusion event into the CCW system in November 2009.
>
> This violation is associated with a Yellow Significance Determination Process finding for Unit 1 in the Initiating Events cornerstone.

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence and the date when full compliance will be achieved is already adequately addressed on the docket in the "St. Lucie Meeting Summary," dated February 26, 2010 (ML100601170). Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation," include the EA number, and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

If you choose to respond, your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. Therefore, to the extent possible, the response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this 19th day of April 2010.

EA-09-321

NRC Bases for Final Significance Determination

On February 19, 2010, the NRC held a regulatory conference with representatives of FPL, St. Lucie Nuclear Plant, to discuss two preliminary Greater than Green inspection findings documented in NRC Inspection Report 05000335, 389/2009006 (ML100210081). These findings concerned issues associated with an October 8, 2008, air intrusion event from the Unit 1 containment instrument air system into the CCW system.

At the regulatory conference, FPL highlighted their assumptions in determining the risk associated with the air intrusion event as Green. These assumptions differed in some instances with those used by the NRC in the preliminary significance determination. In determining the final significance, NRC considered FPL assumptions and factored them into the significance determination process when appropriate. A number of FPL's assumptions were fully accepted and integrated into the NRC final significance determination. These assumptions included: the most probable outcome of air intrusion into the CCW system would be operators terminating the event by isolating the air intrusion source; the dominant accident sequence was operators failing to stop the air intrusion prior to CCW failure followed by operators failing to trip the reactor coolant pumps (RCPs) upon a loss of CCW; and, operators would follow established procedures to the best of their abilities. Also, based upon FPL's input, the final NRC significance determination assumed that operators had time to stop the air intrusion before CCW system failure.

There were several differences between NRC and FPL in NRC's final significance determination. The paragraphs below provide a summary of the differences and the bases for the NRC's final significance determination.

FPL assumed that due to the preponderance of alarms available to the operators, it was highly likely that the operators would trip the reactor and stop the RCPs before CCW system failure would occur. The NRC did not consider these actions in the preliminary significance determination. However, based upon FPL's input, it was included in the final significance determination. The NRC recognized that available alarms would indicate irregular flow in the CCW system and that some of these alarms would direct operators to stop the RCPs and trip the reactor. However, the NRC assumed that the collective set of alarms and indications would provide for competing actions to trip the CCW pumps and/or trip the RCPs. Further, some of the alarms would occur either after CCW failure or at imminent failure. Therefore, assigning a probability to the actions to trip the reactor and stopping the RCPs prior to CCW failure as highly likely was not used. Instead, as an assumption for the final significance determination, a less likely probability than assumed by FPL was assigned by the NRC. Specifically, the NRC assigned a 50/50 probability that operators would trip the reactor and stop the RCPs prior to CCW failure in the final significance determination as compared to FPL, which did not present specific numbers at the conference but, indicated a significantly high probability for operators succeeding in this action.

According to FPL's calculations, the conditional core damage probability associated with the air intrusion event, based upon the latest plant specific PRA and the NRC's SPAR model, varied between 1E-4 & 6E-4. The NRC used the latest available information regarding the RCP seals, the procedures associated with the RCPs, and operator training in updating the NRC's SPAR model of St. Lucie. Further, the NRC, in contrast to FPL, used an 8 hour versus 24 hour exposure time for RCP seal failure in the final conditional core damage probability calculation to account for a standard reactor shutdown.

As a result, the NRC determined that the conditional core damage probability associated with this event was 5.6E-4. Although the NRC applied a different methodology, this numerical result was consistent with the licensee's input and had no affect on the final significance determination.

FPL did not present specific numbers but assumed that the probability of operators failing to recognize and mitigate the air intrusion before CCW pump failure was two to three orders of magnitude less than 1E-1, the number assigned by the NRC, in the preliminary significance determination.

The failure probability used by the NRC for the final significance determination, like FPL, included a dependency, since different crews would be involved in the recognition and mitigation of the air intrusion event. The NRC used a standard Human Reliability Assessment (HRA) protocol in determining the assumption for this operator failure probability in the final significance determination. Like FPL, the performance shaping factors used in the final HRA included 24 hours for operators to recognize and mitigate air intrusion before CCW failure. However, NRC differed from FPL in the performance shaping factor contributions due to the fact that no specific procedure existed to direct operators in diagnosing air intrusion into the CCW system, the high level of complexity associated with diagnosing the source of air intrusion, and limited operator training/experience associated with CCW events of this nature. In its final significance determination, the NRC, after factoring in all the performance shaping factors, used 6.58 E-2 as the probability that operators would not stop the air intrusion into the CCW system prior to pump failure. While FPL did not present specific numbers, their assumptions differed by approximately two to three magnitudes from the NRC. This difference in performance shaping factor assumptions was effectively the most significant difference between the NRC and FPL in determining the final significance associated with the event.

In conclusion, FPL determined, based on best-estimate assumptions, that the delta core damage frequency (CDF) increase was less than 1E-6. The NRC did not agree with FPL's determination of delta CDF being less than 1E-6. Even after factoring in numerous FPL assumptions, NRC determined the delta CDF for the CCW air intrusion performance deficiency to be approximately 2E-5. With this delta CDF being greater than 1E-5, the performance deficiency was classified as Yellow.

ATTACHMENT 2

~~OFFICIAL USE ONLY – SECURITY RELATED INFORMATION~~

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

February 7, 2011

EA-10-241

Mr. Mano Nazar
Executive Vice President and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: TURKEY POINT FINAL SIGNIFICANCE DETERMINATION - NRC INSPECTION REPORT 05000250/2010406 AND 05000251/2010406

Dear Mr. Nazar:

This letter provides you with the final results of our significance determination of the preliminary Greater than Green finding, identified in NRC Inspection Report 05000250/2010404 and 05000251/2010404, dated December 10, 2010. This preliminary Greater than Green finding involved an issue at Florida Power and Light Company's (FPL) Turkey Point Nuclear Plant, and was discussed in detail in the inspection report.

In a telephone conversation with Mr. Michael Ernstes, Chief, Plant Support Branch 2, NRC Region II, on December 17, 2010, Mr. Michael Kiley, Site Vice President, indicated that Turkey Point Nuclear Plant did not contest the significance of the finding and that you declined your opportunity to discuss this issue in a Regulatory Conference or provide a written response.

After considering the information developed during the inspection, the NRC has concluded that the finding is appropriately characterized as Greater than Green (i.e. an issue of at least low to moderate increased importance to safety, which may require additional NRC inspections) in the Physical Security cornerstone.

An appeal of the staff's determination of significance for the identified Greater than Green finding will not be considered as it would not meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 2; that is, since you declined to request a Regulatory Conference or submit a written response, you relinquished your right to appeal the final Significance Determination Process (SDP) determination.

The NRC also has determined that the condition discussed in NRC Inspection Report 05000250/2010404 and 05000251/2010404 is a violation as cited in the enclosed Notice of Violation (Notice). In accordance with the NRC Enforcement Policy, the Notice is considered an escalated enforcement action because it is associated with a Greater than Green finding. The

~~Enclosure(s) transmitted herewith contain(s) SUNSI. When separated from enclosure(s), this transmittal document is decontrolled.~~

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finding had a cross-cutting aspect in the area of Human Performance H.2 (c) in that the licensee failed to ensure that adequate procedures were available to ensure the proper handling and storage of SGI. If you disagree with the characterization of the cross-cutting aspect, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at the Turkey Point Nuclear Plant.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response.

For administrative purposes, this letter is issued as a separate NRC Inspection Report No. 05000250,251/2010406.

Because plant performance for this issue has been determined to be beyond the licensee response band, we will use the NRC's Security Action Matrix to determine the most appropriate NRC response for this event. We will notify you by separate correspondence of that determination.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. However, because of the security related information contained in the enclosure, and in accordance with 10 CFR 2.390, a copy of this letter's enclosures will not be available for public inspection.

Because this issue involves security-related information, your response will not be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. The material enclosed herewith contains security-related information in accordance with 10 CFR 2.390(d)(1) and its disclosure to unauthorized individuals could present a security vulnerability. Therefore, the material will not be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Should you have any questions concerning this letter, please contact Mr. Joel Munday, Director, Division of Reactor Safety, at (404) 997-4600.

Sincerely,

/RA/

Victor M. McCree
Regional Administrator

Docket No.: 50-250, 50-251
License No.: DPR-31, DPR-41

Enclosures:
1. Inspection Report 05000250,251/2010406 **(OUO/Security Related Information)**
2. Notice of Violation **(OUO/Security Related Information)**

cc w/encls: See page 3

~~OFFICIAL USE ONLY – SECURITY-RELATED INFORMATION~~

cc w/encls:
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Site Vice President
Turkey Point Nuclear Plant
Florida Power and Light Company
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Florida City, FL 33035

Robert J. Tomonto
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

July 7, 2011

Mr. Mano Nazar
Executive Vice President and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: TURKEY POINT NUCLEAR PLANT - NRC INSPECTION PROCEDURE 95001 SUPPLEMENTAL INSPECTION REPORT 05000250/2011406 AND 05000251/2011406

Dear Mr. Nazar:

On June 10, 2011, the U.S. Nuclear Regulatory Commission (NRC) staff completed a supplemental inspection pursuant to Inspection Procedure 95001, "Inspection for One or Two White Inputs in a Strategic Performance Area", at your Turkey Point Nuclear Plant, Units 3 and 4. The enclosed inspection report documents the inspection results which were discussed at the exit meeting on June 10, 2011, with Mr. M. Kiley and other members of your staff.

As required by the NRC Reactor Oversight Process Action Matrix, this supplemental inspection was performed because a finding of White safety significance was identified in the third quarter of 2010. The violation was previously documented in NRC Inspection Report 05000250/2010404 and 05000251/2010404, dated December 10, 2010. The NRC staff was informed on February 8, 2011, of your staff's readiness for this inspection.

The objectives of this supplemental inspection were to provide assurance that: (1) the root causes and the contributing causes for the risk-significant issues were understood; (2) the extent of condition and extent of cause of the issues were identified; and (3) corrective actions were or will be sufficient to address and preclude repetition of the root and contributing causes. The inspection consisted of examination of activities conducted under your license as they related to safety, compliance with the Commission's rules and regulations, and the conditions of your operating license.

The inspector determined that your staff performed a comprehensive evaluation of the White finding. Your staff's evaluation identified the primary root cause associated with the finding to be an overall lack of sufficient rigor for receipt of external safeguards information (SGI) by non-security personnel, in that, the Site Vice President's Secretary failed to control a SGI document appropriately. The document was stored in the secretary's non secure desk drawer for approximately four months until discovered by site personnel.

~~**Enclosure (s) transmitted herewith contain(s) SUNSI. When separated from enclosure(s), this transmittal document is decontrolled.**~~

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~~**DISTRIBUTION PERMITTED**~~

Your staff also identified a contributing cause associated with the finding as being a lack of adequate training for notification and recognition of receipt of external NRC SGI information. The inspector determined that the root cause and corrective actions taken to prevent recurrence appear to be adequate.

Based on the results of this inspection, no findings were identified.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system, ADAMS. ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room). However, because of the security-related concerns contained in the enclosure, and in accordance with 10 CFR 2.390, a copy of this letter's enclosure will not be available for public inspection.

In accordance with 10 CFR 2.390(b)(1)(ii), the NRC is waiving the affidavit requirements for your response, if any. This practice will ensure that your response will not be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system, ADAMS. If Safeguards Information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.22. Otherwise, mark your entire response "Security-Related Information-Withhold Under 10 CFR 2.390" and follow the instructions for withholding in 10 CFR 2.390(b)(1).

Sincerely,

/RA/

Michael E. Ernstes, Chief
Plant Support Branch 2
Division of Reactor Safety

Docket No.: 50-250, 50-251
License No.: DPR-31, DPR-41

Enclosure:
Inspection Report 05000250, 251/2011406
w/Attachment: Supplemental Information (OUO)

cc w/encl.: (See page 3)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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ATTACHMENT 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

June 21, 2010

EA-10-037

Mr. Mano Nazar
Executive Vice President
and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION; NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $70,000 (NRC INSPECTION REPORT 05000250/2010009, TURKEY POINT NUCLEAR PLANT)

Dear Mr. Nazar:

This letter provides you with the final significance determination of a preliminary Greater than Green finding and the five apparent violations (AVs) discussed in NRC Inspection Report Nos. 05000250/2010008, dated March 11, 2010, and 05000250, 251/2009005, dated January 28, 2010. The inspection finding was assessed using the NRC's Significance Determination Process and was preliminarily characterized as Greater than Green, which represents a finding with at least low to moderate safety significance that may require additional NRC inspection. The finding involved the failure to properly manage known degradation of Boraflex, a neutron absorber material used in the Turkey Point Unit 3 spent fuel pool (SFP). The NRC's inspection report also identified two AVs associated with the finding, involving: (1) the failure to comply with Technical Specifications (TS) 5.5.1.1.a and 10 CFR § 50.68(b)(4) requirements to assure that the effective neutron multiplication factor (K_{eff}) would be maintained less than 1.0, for all cases in the Unit 3 SFP when flooded with unborated water; and (2) the failure to implement effective corrective actions as required by 10 CFR Part 50, Appendix B, Criterion XVI, for the degradation of Boraflex in the Unit 3 SFP.

NRC Inspection Report Nos. 05000250/2010008 and 05000250, 251/2009005 also identified three AVs that were being considered for escalated enforcement under the NRC's traditional enforcement process. In summary, the AVs involved: (1) failure to provide notification to the NRC in accordance with the requirements of 10 CFR § 50.73 when testing of Boraflex panels in the Unit 3 SFP revealed degradation beyond minimum design values specified in the Updated Final Safety Analysis Report (UFSAR); (2) failure to comply with 10 CFR § 50.59, which requires licensees to maintain records, including written evaluations, which provide the bases for a determination that a change, test, or experiment does not require a license amendment; and (3) failure to update the FSAR in accordance with 10 CFR § 50.71(e) so that the report accurately reflects significant changes made to the facility.

At your request, a Regulatory and Predecisional Enforcement Conference was held on April 14, 2010, to discuss your views on these issues. A meeting summary was issued on April 27, 2010, which included copies of the slide presentation made by Florida Power and Light Company (FPL) (ADAMS Accession # ML101170029). During the conference, FPL staff discussed the circumstances surrounding the Turkey Point Unit 3 Boraflex degradation issues, FPL's assessment of the significance of the preliminary Greater than Green finding, the five AVs, and the corrective actions taken, including the root cause evaluation. At the conference, FPL also summarized its assessment of the finding and concluded that the Unit 3 SFP degradation had no safety significance due, in part, to effective SFP management activities as well as conservatisms in design margins. FPL asserted that the significance of the AVs assessed under the NRC's traditional enforcement process did not rise to the level of escalated enforcement because the AVs did not impede NRC's actions or the regulatory process. However, FPL agreed that the following violations of NRC requirements occurred: (1) failure to comply with TS 5.5.1.1.a; (2) failure to update the UFSAR in accordance with 10 CFR § 50.71(e); and (3) failure to provide notification to the NRC in accordance with 10 CFR § 50.73.

Although FPL agreed that a violation of TS 5.5.1.1.a requirements occurred, they did not agree that a violation of 10 CFR § 50.68(b)(4) occurred, stating that K_{eff} for the SFP storage racks was always maintained within requirements under the conditions specified in 10 CFR § 50.68. With regard to the 10 CFR Part 50, Appendix B, Criterion XVI violation, FPL disagreed with this AV as written. FPL stated that the SFP storage cells described in the Criterion XVI AV summary had degraded below the licensee's established administrative limit, not the design limit as described in the violation summary. FPL also did not agree that a violation of 10 CFR § 50.59 occurred because the licensee stated that the inability to implement License Amendment Request 234, which credited the use of Metamic inserts, did not constitute a proposed change, test, or experiment within the context of 10 CFR § 50.59. The licensee believed they were following the guidance currently described in Regulatory Issue Summary (RIS) 2005-20 with respect to the Boraflex degradation and resulting compensatory measures.

Several technical questions were posed to the licensee during the April 14, 2010, meeting by the NRC. The licensee committed to provide the following additional technical information to the NRC in response to questions and as further clarification: (1) a copy of the 10 CFR § 50.59 review performed for the compensatory measures implemented in the Unit 3 SFP; (2) a copy of the analysis performed that concluded that the most reactive fuel assembly available could be safely placed in the most degraded cell, without credit for either soluble Boron or interim compensatory measures, and K_{eff} would be maintained less than 1.0; (3) copies of NETCO reports for the three BADGER testing campaigns performed in the Unit 3 SFP; (4) an explanation of the statements in FPL Letter L-2001-115 that concluded that the areal density of a measured panel was 0.004 grams of Boron-10 per square centimeter (g-B10/cm^2); and (5) documentation explaining how the uncertainty associated with RACKLIFE and BADGER testing is handled consistent with the 10 CFR § 50.68(b)(4) requirement to determine K_{eff} at a 95 percent probability and 95 percent confidence level.

After considering the information developed during the inspection and information provided by FPL during and after the conference, the NRC has concluded that the finding involving: (1) the failure to comply with the TS 5.5.1.1.a requirement to assure that K_{eff} would be maintained less than 1.0, for all cases in the Unit 3 SFP when flooded with unborated water, and (2) the failure to implement effective corrective actions as required by 10 CFR Part 50, Appendix B, Criterion XVI, for the degradation of Boraflex neutron absorber material below the administrative limits, is appropriately characterized as a White finding of low to moderate significance with regard to safety, which will require additional NRC inspections.

The NRC concluded that licensee data are insufficient to support the conclusion that, when accounting for identified degradation of Boraflex panels in the Turkey Point Unit 3 spent fuel storage racks, K_{eff} would have been maintained less than 1.0 for all cases when flooded with unborated water as required by TS 5.5.1.1.a, which includes minimum design values as expressed in Chapter 9 of the UFSAR. The NRC notes that, as FPL presented at the conference, the actual soluble boron concentration remained at sufficient levels such that a criticality event would be highly unlikely, given the degraded Boraflex panels in the Turkey Point Unit 3 spent fuel storage racks. In addition, FPL implemented compensatory measures including increasing soluble boron concentration levels, to ensure that the SFP remained subcritical, as the NRC acknowledged in Confirmatory Action Letter (CAL) RII-10-002, dated December 19, 2009.

This conclusion is based on a review of the Turkey Point Unit 3 SFP current licensing basis criticality analysis, as approved by the NRC in 2000, which determined that the calculated maximum K_{eff} provided a limited margin to criticality. Chapter 9 of the Turkey Point UFSAR states, in part, that the most limiting depletion of Boron-10 from the Boraflex fuel storage racks was a reduction of nominal Boron-10 areal density of 50 percent for Region II racks. This analysis attempted to account for known Boraflex degradation issues by assuming a reduced Boron-10 areal density of 0.006 g-B10/cm^2 in the Boraflex, which represents a reduction in the nominal Boron-10 areal density of 50 percent. However, the on-going Boraflex degradation at Turkey Point necessitated an effective Boraflex surveillance program to assure that the minimum areal density did not exceed the design basis limits. Due to the limited margin available in the Unit 3 SFP criticality analysis and the small number of storage cells actually tested, degradation that results in areal densities below the assumed values expressed in Chapter 9 of the UFSAR could reasonably be assumed to result in a K_{eff} equal to or greater than 1.0 and a criticality, if flooded with unborated water.

Although the generic aspects of compliance with 10 CFR 50.68 remain under review, the NRC has concluded that the specific circumstances of the Turkey Point 10 CFR 50.68 matter are appropriately resolved via citation of TS 5.5.1.1.a.

The staff determined that the information provided by the licensee did not have an appreciable impact on the NRC Inspection Manual Chapter (IMC) 0609 Appendix M analysis. The staff also determined that the finding had a cross-cutting aspect in the area of Problem Identification and Resolution since the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1(d)). After further review, the cross-cutting aspect associated with P.1(c), as discussed in NRC Inspection Report 05000250/2010008, is no longer applicable.

Regarding the three AVs assessed under the NRC's traditional enforcement process, based on the information developed during the inspection and the information you provided during and after the conference, the NRC has determined that two violations of NRC requirements occurred. One of these violations is cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding it are described in detail in the subject inspection report. In summary, FPL failed to provide notification to the NRC in accordance with the requirements of 10 CFR § 50.73 when testing and evaluation of Boraflex panels in the Unit 3 SFP racks revealed Boraflex degradation beyond minimum design values specified in the UFSAR. The NRC considers the failure to provide the required notification to be a significant matter because it impacted the NRC's ability to review and assess FPL's corrective actions for managing SFP Boraflex degradation. Had this information been reported as required, it is very likely that the NRC would have initiated additional follow-up inspections and inquiries into the degradation of the Unit 3 SFP from 2004 onward.

In addition, as discussed in the Enforcement Policy, the severity level of a violation involving the failure to make a required report to the NRC will be based upon the significance of and the circumstances surrounding the matter that should have been reported. In this case and as discussed above, the NRC concluded that the failure to provide the required report is associated with a White finding for FPL's failure to adequately manage Unit 3 FPL Boraflex degradation. Based on the above, the significance of this violation is characterized at Severity Level III in accordance with the NRC Enforcement Policy.

In accordance with the Enforcement Policy, a base civil penalty in the amount of $70,000 is considered for a Severity Level III violation. Because your facility has not been the subject of escalated enforcement action within the last 2 years, the NRC considered whether credit was warranted for *Corrective Action* in accordance with the civil penalty assessment process in Section VI.C.2 of the Enforcement Policy.

At the enforcement conference, FPL offered no substantive root cause assessment of its failure to make the required notification in accordance with 10 CFR § 50.73, and did not provide any detailed corrective actions to allow the NRC to conclude that its actions in response to the violation were prompt and comprehensive. Therefore, credit is not warranted for the factor of *Corrective Action*.

Therefore, to emphasize the importance of prompt correction of violations, I have been authorized, after consultation with the Director, Office of Enforcement, to issue the enclosed Notice of Violation and Proposed Imposition of Civil Penalty (Notice) in the base amount of $70,000 for this Severity Level III violation.

A second violation was identified involving the failure to update the UFSAR in accordance with 10 CFR § 50.71(e). The significance of this violation is characterized at Severity Level IV because it did not significantly impede the NRC's regulatory process. This violation is non-cited because the criteria of Section VI.A.1 of the NRC Enforcement Policy have been satisfied.

Regarding the AV associated with 10 CFR § 50.59, the NRC determined that the additional information provided by FPL after the conference established a sufficient basis for the NRC to conclude that a violation did not occur. In this case, the NRC concluded that FPL followed the guidance currently described in RIS 2005-20 with respect to Boraflex degradation and resulting compensatory measures. Therefore, the NRC concluded that a violation of 10 CFR § 50.59 did not occur.

You have 30 calendar days from the date of this letter to appeal the staff's significance determination for the White finding or the Notice of Violation and Proposed Civil Penalty. An appeal of the White finding will be considered to have merit only if it meets the criteria given in NRC IMC 0609, Attachment 2.

For administrative purposes, this letter is issued as a separate NRC Inspection Report, No. 05000250/2010009. Accordingly, AVs 05000250/2009-005-03, 04, 05 and 06 are closed. AV 05000250/201008-01 is considered withdrawn. The following violations are open: Violation 05000250/201009-01, Failure to properly manage known Turkey Point Unit 3 Boraflex spent fuel pool degradation and the cross-cutting aspect associated with this finding in the area of Effective Corrective Actions, P.1(d); Violation 05000250/201009-02, Failure to make notification to the NRC in accordance with the requirements of 10 CFR § 50.73 when testing of Boraflex panels in the Unit 3 SFP revealed degradation beyond minimum design values specified in the Updated Final Safety Analysis Report (UFSAR) with no cross-cutting aspect; and Non-cited Violation 05000250/201009-03, Failure to update the FSAR in accordance with 10 CFR § 50.71(e) so that the report accurately reflects significant changes made to the facility with no cross-cutting aspect.

Because plant performance for this issue has been determined to be beyond the licensee response band of the NRC Action Matrix, we will use the Action Matrix to determine the most appropriate NRC response for this event. We will notify you, by separate correspondence, of that determination.

You are required to respond to this letter and should follow the instructions specified in the NUREG/BR-0254, Rev. 5 at the following link, http://www.nrc.gov/reading-rm/doc-collections/nuregs/brochures/br0254/r5/br0254r5.pdf.

In accordance with 10 CFR § 2.390 of the NRC's "Rules of Practice," a copy of this letter, Enclosure 1, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such information, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR § 2.390(b) to support a request for withholding confidential commercial or financial information). The NRC also includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/.

Should you have any questions concerning this letter, please contact Mr. Marvin Sykes at 404-997-4629.

Sincerely,

/RA/

Luis A. Reyes
Regional Administrator

Docket No.: 50-250
License No.: DPR-31

Enclosure: Notice of Violation and Proposed Imposition of Civil Penalty

cc w/Encl: (see page 7)

Should you have any questions concerning this letter, please contact Mr. Marvin Sykes at 404-997-4629.

Sincerely,

/RA/

Luis A. Reyes
Regional Administrator

Docket No.: 50-250
License No.: DPR-31

Enclosure: Notice of Violation and Proposed Imposition of Civil Penalty

cc w/Encl: (see page 7)

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cc w/encl:
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Nuclear Licensing
Florida Power & Light Company
Electronic Mail Distribution

Larry Nicholson
Director
Licensing
Florida Power & Light Company
Electronic Mail Distribution

Michael Kiley
Site Vice President
Turkey Point Nuclear Plant
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Mike A. Shehadeh, P.E.
City Manager
City of Homestead
Electronic Mail Distribution

Gene St. Pierre
Vice President, Fleet Support
Florida Power & Light Company
Electronic Mail Distribution

Letter to Mano Nazar from Luis Reyes dated June 21, 2010

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION; NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $70,000 (NRC INSPECTION REPORT 05000250/2010009, TURKEY POINT NUCLEAR PLANT)

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NOTICE OF VIOLATION
AND PROPOSED IMPOSITION OF A CIVIL PENALTY

Florida Power and Light
Turkey Point Nuclear Plant
Unit 3

Docket Nos. 50-250
License No. DPR-31
EA-10-037

The NRC identified violations of NRC requirements during an inspection and in-office review completed on December 31, 2009, and on March 5, 2010. In accordance with the NRC Enforcement Policy, the NRC proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (Act), 42 U.S.C. § 2282, and 10 CFR § 2.205. The particular violations and associated civil penalty is set forth below:

I. Violation Assessed a Civil Penalty

10 CFR § 50.73(a)(2)(B) states that the licensee shall report to the NRC any condition which was prohibited by the plant's Technical Specifications (TS).

TS 5.5.1.1.a states that the Unit 3 spent fuel storage racks are designed and shall be maintained with an effective neutron multiplication factor (K_{eff}) less than 1.0 when flooded with unborated water, which includes an allowance for biases and uncertainties as described in the Updated Final Safety Analysis Report (UFSAR), Chapter 9.

Contrary to the above, from 2004 to May 10, 2010, the licensee failed to report a condition that was prohibited by its TS. Specifically, testing since 2004 revealed that Unit 3 spent fuel pool Boraflex degradation exceeded values such that the Unit 3 spent fuel storage racks would not be maintained with K_{eff} less than 1.0 when flooded with unborated water when considering the biases and uncertainties described in Chapter 9 of the UFSAR. This condition is prohibited by Turkey Point Unit 3 TS, but it was not reported to the NRC as required by 10 CFR § 50.73(a)(2)(B).

This is a Severity Level III violation (Supplement I).
Civil Penalty - $70,000 (EA-10-037).

II. Violations Not Assessed a Civil Penalty

A. TS 5.5.1.1.a states that the Unit 3 spent fuel storage racks are designed and shall be maintained with a K_{eff} less than 1.0 when flooded with unborated water, which includes an allowance for biases and uncertainties as described in Chapter 9 of the UFSAR.

Chapter 9 of the Turkey Point UFSAR states, in part, that the most limiting depletion of Boron-10 from the Boraflex fuel storage racks was a reduction of nominal Boron-10 areal density of 50 percent for Region II racks.

Contrary to the above, the licensee failed to maintain the Unit 3 spent fuel storage racks such that K_{eff} would remain less than 1.0 when flooded with unborated water when considering the biases and uncertainties described in Chapter 9 of the UFSAR. Specifically, licensee data indicates that dissolution of Boron-10 from Boraflex panels in Region II of the

Turkey Point Unit 3 spent fuel pool resulted in a reduction in the nominal Boron-10 areal density in excess of 50 percent, such that K_{eff} would not have been maintained less than 1.0 for all cases if the spent fuel pool had been flooded with unborated water.

B. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected.

Turkey Point UFSAR page 9.5-12 states that the most limiting case obtained to assure K_{eff} was equivalent to less than 1.0 in Region II was a reduction of Boraflex nominal areal density by 50 percent.

Contrary to the above, a condition adverse to quality was not promptly identified and corrected. Specifically, in 2004 and 2007, the licensee identified two spent fuel pool storage cells with Boraflex degradation greater than an administrative action limit specified in Turkey Point Plant Curve Book, Section 5. However, the licensee failed to correct this condition adverse to quality until it was identified by NRC inspectors in December 2009.

These violations are associated with a White Significance Determination Process finding for Unit 3 in the Initiating Events cornerstone.

Pursuant to the provisions of 10 CFR 2.201, the Florida Power and Light Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-10-037" and for each violation should include: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, the NRC may issue an order or a Demand for Information requiring you to explain why your license should not be modified, suspended, or revoked or why the NRC should not take other action as may be proper. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Within the same time provided for the response required under 10 CFR 2.201, the Licensee may pay the civil penalty proposed above in accordance with NUREG/BR-0254 and by submitting to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, a statement indicating when and by what method payment was made, or may protest imposition of the civil penalty in whole or in part, by a written answer addressed to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission. Should the Licensee fail to answer within 30 days of the date of this Notice, the NRC will issue an order imposing the civil penalty. Should the Licensee elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalty, in whole or in part, such answer should be clearly marked as an "Answer to a Notice of Violation" and may: (1) deny the violation(s) listed in this Notice, in whole or in part; (2) demonstrate extenuating circumstances; (3) show error in this Notice; or (4) show other reasons why the penalty should not be imposed. In addition to protesting the civil penalty in whole or in part, such answer may request remission or mitigation of the penalty.

In requesting mitigation of the proposed penalty, the response should address the factors addressed in Section VI.C.2, "Civil Penalty Assessment," of the Enforcement Policy. Any written answer addressing these factors pursuant to 10 CFR 2.205, should be set forth separately from the statement or explanation provided pursuant to 10 CFR 2.201, but may incorporate parts of the 10 CFR 2.201 reply by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. The attention of the Licensee is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing a civil penalty.

Upon failure to pay any civil penalty which subsequently has been determined in accordance with the applicable provisions of 10 CFR 2.205 to be due, this matter may be referred to the Attorney General, and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282c.

The responses noted above, i.e., Reply to Notice of Violation, Statement as to payment of civil penalty, and Answer to a Notice of Violation, should be addressed to: Roy Zimmerman, Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region II, 245 Peachtree Center Avenue, Suite 1200, Atlanta, GA 30303-1257, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request that such material is withheld from public disclosure, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this 21st day of June 2010

Enclosure

ATTACHMENT 4

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ATTACHMENT 5

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 4, 2011

Mr. Mano K. Nazar
Senior Vice President and Chief Nuclear Officer
Florida Power & Light Company
Mail Stop NNP/JB
700 Universe Boulevard
Juno Beach, FL 33408-0420

SUBJECT: NRC INSPECTION REPORT NOS. 05200040/2011-201 AND 05200041/2011-201 AND NOTICE OF VIOLATION

Dear Mr. Nazar:

On February 28, 2011 through March 4, 2011, the U.S Nuclear Regulatory Commission (NRC) conducted an inspection at the headquarters of Florida Power & Light Company (FPL) in Juno Beach, FL. The purpose of the NRC inspection was to verify that FPL effectively implemented quality assurance (QA) processes and procedures for activities related to the Turkey Point Units 6 and 7 combined license application. The inspection focused on assessing compliance with the provisions of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 21, "Reporting of Defects and Noncompliance," and selected portions of Appendix B, "Quality Assurance Program Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." The enclosed report presents the results of this inspection.

Based on the results of this inspection, the NRC determined that two Severity Level IV violations of NRC requirements occurred. The NRC evaluated the violations in accordance with the agency's Enforcement Policy, which is available on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

These violations are cited in the enclosed Notice of Violation (Notice) and circumstances surrounding it are described in detail in the subject inspection report. The violations are being cited in the Notice because the NRC inspection team identified examples in which FPL failed to adequately implement aspects of its Part 21 program and its corrective action program in accordance with Appendix B to 10 CFR Part 50.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding," of NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's Agencywide Documents Access and Management System, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy, proprietary, or Safeguards Information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request that such material be withheld from public disclosure, you must specifically identify the portions of your response that you seek to have withheld and provide, in detail, the bases for your claim (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If Safeguards Information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21, "Protection of Safeguards Information: Performance Requirements."

Sincerely,

Juan Peralta, Chief
Quality and Vendor Branch 1
Division of Construction Inspection
& Operational Programs
Office of New Reactors

Docket Nos.: 05200040 and 05200041

Enclosures:
1. Notice of Violation
2. Inspection Report Nos. 05200040/2011-201 and 05200041/2011-201 and Attachment

NOTICE OF VIOLATION

Florida Power & Light Company
Turkey Point Units 6 and 7
Juno Beach, FL

Docket Nos.: 05200040 and 05200041
Report No. 2011-201

During a U.S. Nuclear Regulatory Commission (NRC) inspection conducted at the headquarters offices of Florida Power Light & Company (FPL) in Juno Beach, FL, on February 28 through March 4, 2011, the NRC inspection team identified violations of NRC requirements. In accordance with the NRC Enforcement Policy, the violations are described below:

A. Title 10 of the *Code of Federal Regulations* (10 CFR) 21.21(a), requires, in part, that each individual, corporation, partnership, or other entity subject to 10 CFR Part 21, "Reporting of Defects and Noncompliance," adopt appropriate procedures to evaluate deviations and failures to comply associated with substantial safety hazards (SSH) as soon as practicable.

   In addition, 10 CFR 21.21(d)(3)(i), requires, in part, that an initial notification by facsimile or telephone be made to the NRC Operations Center within 2 days following receipt of information by the director or responsible corporate officer regarding identification of a defect or a failure to comply.

   Furthermore, 21.21(d)(3)(ii), requires, in part, that a written notification be provided to the NRC within 30 days following receipt of information by the director or responsible corporate officer regarding identification of a defect or a failure to comply.

   Contrary to the above, as of March 4, 2011, FPL has not adopted appropriate procedures to evaluate deviations and failures to comply associated with SSH, and to notify the NRC following receipt of information by the director or responsible corporate officer regarding identification of a defect or a failure to comply. Specifically, FPL procedures ENG-QI-2.2, "10 CFR 21 SSH Evaluation/Reporting," Revision 6, dated July 10, 2010, and IP-801, "Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21," Revision 15, dated September 8, 2008, do not contain the requisite guidance for the effective evaluation of deviations and failures to comply associated with SSH nor to notify the NRC within the timeframes established by 10 CFR Part 21.21(d)(3). In addition, ENG-QI-2.2 and IP-801 included definitions that differed from those provided in 10 CFR 21.3, "Definitions," thus altering the intended meaning of the terms.

This issue has been identified as Violations 05200040/2011-201-01 and 05200041/2011-201-01.

This is a Severity Level IV violation (Section 6.5.d of the NRC Enforcement Policy).

B. Criterion XVI, "Corrective Action," of Appendix B, "Quality Assurance Program Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," states, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

Section A.6 of FPL-1, "Quality Assurance Topical Report," Revision 8, dated October 22, 2010, states, in part, that a corrective action program is implemented to promptly identify, control, document, classify, and correct conditions adverse to quality.

Contrary to the above, as of March 4, 2011, FPL failed to establish measures to ensure conditions adverse to quality, such as deviations, and nonconformances are promptly identified and corrected. Specifically, FPL failed to promptly correct nonconformances identified in Action Request (AR) 00477542, "Control of RAI, RFI, and NRC Correspondence QA Records," dated May 11, 2010. In addition, FPL failed to correctly identify and document the existence of deviations in AR 01622965, "New Plant OE - Part 21 Reporting Procedure," dated February 23, 2011.

This issue has been identified as Violations 05200040/2011-201-02 and 05200041/2011-201-02.

This is a Severity Level IV violation (Section 6.5.d of the NRC Enforcement Policy).

In accordance with the provisions of 10 CFR 2.201, "Notice of Violation," FPL is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Chief, Quality and Vendor Branch 1, Division of Construction Inspection and Operational Programs, Office of New Reactors, within 30 days of the date of the letter transmitting this Notice of Violation. This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations; and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC Agencywide Documents Access and Management System, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or Safeguards Information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If Safeguards Information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21, "Protection of Safeguards Information: Performance Requirements."

response, please provide the level of protection described in 10 CFR 73.21, "Protection of Safeguards Information: Performance Requirements."

In accordance with 10 CFR 19.11, "Postings of Notices to Workers," you may be required to post this notice within 2 working days of receipt.

Dated at Rockville, MD, this XXth day of April 2011.

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF NEW REACTORS
DIVISION OF CONSTRUCTION INSPECTION AND OPERATIONAL PROGRAMS

Docket Nos.:	05200040 and 05200041	
Report Nos.:	05200040/2011-201 and 05200041/2011-201	
Applicant:	Florida Power & Light Company 700 Universe Boulevard Juno Beach, FL 33408-0420	
Applicant Contact:	Mr. Steve Franzone New Nuclear Project Licensing Manager	
Background:	Florida Power & Light Company is pursuing a combined license for two new AP1000 units at the Turkey Point site in Miami-Dade County, FL.	
Inspection Dates:	February 28 – March 4, 2011	
Inspectors:	Yamir Diaz-Castillo	NRO/DCIP/CQVA Team Leader
	Kerri Kavanagh	NRO/DCIP/CQVA
	Stacy Smith	NRO/DCIP/CQVB
	Marlayna Vaaler	NRO/DCIP/CQVA
	Brent Clarke	NRO/DCIP/CQVA
Project Manager:	Manny Comar	NRO/DNRL/NWE1
Approved by:	Juan D. Peralta, Chief Quality and Vendor Branch 1 Division of Construction Inspection and Operational Programs Office of New Reactors	

EXECUTIVE SUMMARY

Florida Power & Light Company
Report Nos. 05200040/2011-201 and 05200041/2011-201

The U.S. Nuclear Regulatory Commission (NRC) inspection focused on quality assurance (QA) policies and procedures implemented to support the combined license application (COLA) for Turkey Point (TP) Units 6 and 7, as described in NRC Inspection Manual Chapter 2502, "Construction Inspection Program: Pre-Combined License (Pre-COL) Phase," dated October 3, 2007. The purpose of this inspection was to verify that Florida Power & Light Company (FPL) had implemented an adequate quality assurance (QA) program that complies with the requirements of Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "Domestic Licensing of Production and Utilization Facilities." The inspection also verified that FPL had implemented a program under 10 CFR Part 21, "Reporting of Defects and Noncompliance," that meets NRC regulatory requirements.

The NRC based its inspection on the following:

- 10 CFR Part 21
- Appendix B to 10 CFR Part 50

During this inspection, the NRC inspection team implemented Inspection Procedure (IP) 35017, "Quality Assurance Implementation Inspection," dated July 29, 2008, and IP 36100, "Inspection of 10 CFR Parts 21 and 50.55(e) Programs for Reporting Defects and Noncompliance," dated October 3, 2007.

The NRC had not performed any QA inspections at FPL for the TP Units 6 and 7 COLA before this inspection.

<u>10 CFR Part 21 Program</u>

The NRC inspection team concluded that FPL is not implementing its Part 21 program consistent with the requirements of 10 CFR Part 21. The NRC inspection team issued Violations 05200040/2011-201-01 and 05200041/2011-201-01 for FPL's failure to adopt appropriate procedures in accordance with 10 CFR 21.21, "Notification of Failure To Comply or Existence of a Defect and its Evaluation." Specifically, the NRC inspection team determined that FPL's procedures ENG-QI-2.2, "10 CFR 21 SSH Evaluation/Reporting," Revision 6, dated July 10, 2010, and IP-801, "Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21," Revision 15, dated September 8, 2008, were not appropriate procedures to evaluate deviations and failures to comply associated with SSHs and to notify the NRC within the required timeframe of identification of a defect or a failure to comply. In addition, ENG-QI-2.2 and IP-801 included definitions that differed from those provided in 10 CFR 21.3, "Definitions," that altered the intended meaning of the terms.

Design Control

The NRC inspection team concluded that the implementation of the FPL design control process is consistent with the regulatory requirements of Criterion III, "Design Control," of Appendix B to 10 CFR Part 50. Based on its review, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

Procurement Document Control

The NRC inspection team concluded that the implementation of the FPL procurement document control process is consistent with the regulatory requirements of Criterion IV, "Procurement Document Control," of Appendix B to 10 CFR Part 50. Based on its review, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

Document Control

The NRC inspection team concluded that the implementation of the FPL document control process is consistent with the regulatory requirements of Criterion VI, "Document Control," of Appendix B to 10 CFR Part 50. Based on its review, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

Control of Purchased Equipment, Materials, and Services

The NRC inspection team concluded that the implementation of FPL's control of purchased equipment, materials and services process is consistent with the regulatory requirements of Criterion VII, "Control of Purchased Material, Equipment, and Services" of Appendix B to 10 CFR Part 50. Based on its review, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

Corrective Actions

The NRC inspection team concluded that FPL is not implementing its Corrective Action Program consistent with the requirements of Criterion XVI, "Corrective Action," of Appendix B to 10 CFR Part 50. The NRC inspection team issued Violations 05200040/2011-201-02 and 05200041/2011-201-02 for FPL's failure to establish measures to ensure conditions adverse to quality, such as deviations and nonconformances are promptly identified and corrected. Specifically, FPL failed to promptly correct nonconformances identified in closed Action Request 00477542, "Control of RAI, RFI, and NRC Correspondence QA Records," dated May 11, 2010. In addition, FPL failed to correctly identify and document the existence of deviations in AR 01622965, "New Plant OE - Part 21 Reporting Procedure," dated February 23, 2011.

Internal Audits

The NRC inspection team concluded that the implementation of FPL's internal audit process is consistent with the regulatory requirements of Criterion XVIII, "Audits," of Appendix B to 10 CFR Part 50. Based on its review, the NRC inspection team determined that FPL is effectively

Quality Assurance Records

With the exception of Violations 05200040/2011-201-02 and 05200041/2011-201-02 in relation to FPL's failure to correct conditions adverse to quality associated with storage of QA records in an adequate and timely manner, the NRC inspection team concluded that the implementation of FPL's QA records program is consistent with the regulatory requirements of Criterion XVII, "Quality Assurance Records," of Appendix B to 10 CFR Part 50.

REPORT DETAILS

1. 10 CFR Part 21 Program

a. Inspection Scope

The U.S. Nuclear Regulatory Commission (NRC) inspection team reviewed the implementation of the Florida Power & Light Company's (FPL's) program under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 21, "Reporting of Defects and Noncompliance," in support of the combined license application (COLA) for Turkey Point (TP), Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of the FPL Part 21 program to verify compliance with the regulatory requirements of 10 CFR Part 21. The NRC inspection team also discussed this process with members of FPL management and technical staff.

The NRC inspection team reviewed the following documents for this inspection area:

- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010
- QI 16 QAD 6, "10 CFR Part 21 Tracking (Information Use)," Revision 17, dated June 12, 2009
- PI-AA-204: "Condition Identification and Screening Process," Revision 10, dated August 30, 2010.
- ENG-QI 2.2, "10 CFR 21 SSH Evaluation/Reporting," Revision 6, dated July 10, 2010
- Form 145, "Substantial Safety Hazard Determination Checklist," Revision 1, dated September 2009
- NP 808, "Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21," Revision 7, dated October 26, 2009
- EN-AA-203-1100, "Engineering Evaluations," Revision 1, dated February 24, 2011
- JDM-WP-009, "NRC Posting Requirements," Revision 1, dated December 9, 2009
- IP 801, "Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21," Revision 15, dated September 8, 2008
- ENG-QI 6.6, "Glossary," Revision 11, dated July 10, 2010
- Action Request Number 01623985, "Periodic Review of IP 801 Evaluating and Reporting Defects," dated February 25, 2010
- Action Request Number 01624655, "Procedure QI-2-NNP-01 Requires Additional Detail," dated February 28, 2011

- Action Request Number 01624489, "Review of 10 CFR Part 21 Evaluations Are Sometimes Greater Than 60 Days," dated February 28, 2011
- Action Request Number 01625239, "NRC IP 36100 Part 21 Inspection Improvement Opportunities," dated March 2, 2011
- Action Request Number 01622965, "New Plant OE – Part 21 Reporting Procedure," dated February 23, 2011
- Action Request Number 001625890, "Misuse of Part 21 Terminology," dated March 3, 2011
- Action Request Number 001625226, "Part 21 Process Ties Include Various Procedures and Departments," dated March 2, 2011

b. Observations and Findings

b.1 Postings

The NRC inspection team verified that FPL had posted notices that included: (1) a copy of Section 206 of the Energy Reorganization Act of 1974; (2) a description of 10 CFR Part 21 and the FPL procedure that implements the regulation; and (3) the name of the individual to whom reports could be made.

b.2 Purchase Orders

The NRC inspection team reviewed a sample of FPL's purchase orders (POs) to verify that FPL had implemented a program consistent with the requirements described in 10 CFR 21.31, "Procurement Documents," regarding specifying the applicability of 10 CFR Part 21 in its POs for safety-related services. The NRC inspection team verified that FPL imposed the requirements of 10 CFR Part 21 on qualified suppliers having programs meeting the requirements of Appendix B to 10 CFR Part 50.

b.3 10 CFR Part 21 Procedures and Implementation

Inspection Procedure (IP) 801 specifies the measures and responsibilities in place to ensure compliance with 10 CFR Part 21. This procedure provides a system for receipt and identification, notification of appropriate organizations, and evaluation of information concerning failures to comply and defects in facilities, activities, or basic components which could create a substantial safety hazard (SSH).

Step 5.2 of IP-801 discusses defect evaluations and states, in part, that an engineering evaluation *may* be accomplished via site specific quality instructions. Although there are multiple procedures that discuss engineering evaluations, there is no procedural connection between IP-801 and the site specific quality instructions that provides guidance on how to perform an engineering evaluation. FPL personnel responsible for the Part 21 program informed the NRC inspection team that ENG-QI 2.2 was used by engineering to perform SSH evaluations. IP-801 and ENG-QI 2.2 both have criteria to determine if a defect exists, but are inconsistent in the way they screen potential deviations. The NRC inspection team concluded that the FPL procedures were not appropriate for evaluating deviations and failures to comply.

The NRC inspection team identified this issue as an example of Violations 05200040/2011-201-01 and 05200041/2011-201-01.

In addition, the NRC inspection team noted that the definitions for deviation, defect, and discovery contained in IP-801 and ENG-QI-2.2 were inconsistent with the definitions contained in 10 CFR 21.3, "Definitions." Specifically, the definitions for defect and deviation failed to include that a deviation could be a departure from technical requirements in early site permit information, a standard design certification or a standard design approval. The use of these terms within the body of IP-801 and ENG-QI-2.2 could cause a departure from technical requirements to not be identified as a deviation. The NRC inspection team identified this issue as another example of Violations 05200040/2011-201-01 and 05200041/2011-201-01.

Furthermore, the NRC inspection team determined that procedures IP-801 and ENG-QI 2.2 lacked guidance for the evaluation of deviations or failures to comply consistent with the timeliness requirements of 10 CFR 21.21(d). Specifically, ENG-QI 2.2 does not provide guidance to notify the NRC Operations Center by telephone or fax within two days of notifying the director or responsible officer nor to provide written notification within 30 days following the identification of a defect or failure to comply, as required in paragraph 21.21(d). The NRC inspection team identified this issue as another example of Violations 05200040/2011-201-01 and 05200041/2011-201-01.

The NRC inspection team noted that FPL had performed no Part 21 evaluations as a part of the TP Units 6 and 7 COLA. The NRC inspection team reviewed a sample of action request (AR) reports and identified no issues that would have warranted reportability under the FPL Part 21 program.

Conclusions

The NRC inspection team concluded that FPL is not implementing its Part 21 program consistent with the requirements of 10 CFR Part 21. The NRC inspection team issued Violations 05200040/2011-201-01 and 05200041/2011-201-01 for FPL's failure to adopt appropriate procedures in accordance with 10 CFR 21.21, "Notification of Failure To Comply or Existence of a Defect and its Evaluation." Specifically, the NRC inspection team determined that FPL's procedures ENG-QI-2.2, "10 CFR 21 SSH Evaluation/Reporting," Revision 6, dated July 10, 2010, and IP-801, "Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21," Revision 15, dated September 8, 2008, were not appropriate procedures to evaluate deviations and failures to comply associated with SSHs and to notify the NRC within the required timeframe of identification of a defect or a failure to comply. In addition, ENG-QI-2.2 and IP-801 included definitions that differed from those provided in 10 CFR 21.3, "Definitions," that altered the intended meaning of the terms.

2. Design Control

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL and Bechtel design control process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of the FPL and Bechtel design control process to verify compliance with the regulatory requirements of Criterion III, "Design Control," of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010

- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010

- NNP-PI-08, "COLA Review and Acceptance Process," Revision 4, dated September 10, 2010

- NNP-PI-04, "COLA Configuration Control and Responses to Requests for Additional Information for Project Applications," Revision 2, dated September 10, 2010

- NNP-PI-011, "Change Control for COL Application Plant Specific Design Information," Revision 2, dated August 30, 2010

- Turkey Point Units 6 and 7 Combined License Application Part 7, "Departures and Exemption Requests," Revision 2, December 21, 2010

- PTN DEP 19.58-1, "Core Damage Frequency DCD Departure," Revision 0, dated June 22, 2009

- PTN DEP 2.0-1, "Operating Basis Wind Speed," Revision 0, dated June 22, 2009

- PTN DEP 2.0-3, "Wet Bulb Safety Air," Revision 0, dated June 22, 2009

- Screen/Evaluation Number 2009-002, dated June 15, 2009

- Screen/Evaluation Number 2009-003, dated June 15, 2009

b. Observations and Findings

b.1 Policies and Procedures

The NextEra Energy (NEE) quality assurance topical report (QATR) states, in part, that provisions to control design inputs, processes, outputs, changes, interfaces, records, and organizational interfaces ensure that design inputs (e.g., design bases and the performance, regulatory, quality, and quality verification requirements) are correctly translated into design outputs (e.g., specifications, drawings, procedures, and instructions) such that the final design output can be related to the design input in sufficient detail to permit verification. Design processes provide for design verification (as described in Section B.3 of the QATR) to ensure that items and activities subject to the provisions of the QATR are suitable for their intended application, consistent with their effect on safety.

Section 6.3 of QI-2-NNP-01 states, in part, that the New Nuclear Project (NNP) commits to the applicable requirements established in NEE QATR, Sections B.2, "Design Control," and B.3, "Design Verification." FPL has contracted all safety-related combined license design activities to Bechtel.

NNP-PI-011 states, in part, that its purpose is to provide standardized instructions and personnel training and qualification requirements for performing reviews of proposed plant-specific changes to the information contained in a generic design control document (DCD). These reviews are conducted in accordance with Section VIII of Appendix D, "Design Certification Rule for the AP1000 Design," to 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants." (The AP1000 design certification rule establishes the process for evaluating these changes.) The instruction provides guidance to identify those changes that can be performed by FPL without prior NRC review and to distinguish them from changes that require NRC review and approval. FPL has contracted some of the TP Units 6 and 7 plant-specific AP1000 DCD departure analyses to Westinghouse Electric Company (WEC), while performing the remaining analyses in-house.

Bechtel 3DP-G04-00001 defines the requirements for preparation and control of project and task design criteria. Design criteria include client requirements and those standards, codes, regulations, and design bases which shall be used for the project or task design.

Bechtel 3DP-G04G-00037 defines the engineering department requirements for preparing, checking (verifying), approving, revising, filing, retaining, and releasing calculations.

b.2 <u>Design Packages Supporting the Turkey Point Units 6 and 7 Combined License Application</u>

The NRC inspection team reviewed the design control process for Bechtel and the implementation of procedures and policy guidelines governing the process as applied to TP Units 6 and 7. At the time of the inspection, Bechtel had completed 54 safety-related calculations to support the TP COLA. The majority of these calculations supported the geotechnical and hydraulic engineering sections of the TP final safety analysis report (FSAR). The NRC inspection team selected a sample of five design calculation packages and the associated design verification reports that established the design-basis input to several chapters of the TP FSAR. The NRC inspection team noted that three of the calculations reviewed utilized computer software which was validated and verified in accordance with Bechtel procedures.

The NRC inspection team verified that each calculation package contained the design bases, assumptions, and methodology used to develop the calculations, results, and conclusions. The associated design verification reports were performed by individuals who did not perform the analysis and were completed before the calculation being used to support other calculations or TP FSAR sections. The NRC inspection team noted that the samples it reviewed were consistent with the process contained in the Bechtel procedures.

b.3 <u>Turkey Point AP1000 Design Control Document Departure Evaluation Packages</u>

Part 7 of the TP Units 6 and 7 COLA identifies six departures that can be implemented without prior NRC approval and three departures that require NRC approval before implementation. WEC prepared the departure evaluation packages for four of the departures that did not require prior NRC approval for implementation and two of the departures that did require NRC approval before implementation.

The NRC inspection team reviewed three departure evaluation packages prepared by WEC and two departure evaluation packages prepared by FPL. WEC departure evaluation packages, PTN DEP 2.0-1 and PTN DEP 2.0-3, as well as FPL departure evaluation package, Screen/Evaluation Number 2009-003, were identified as departures that require NRC approval before implementation. PTN DEP 19.58-1 and Screen/Evaluation Number 2009-002 were identified as departures that can be implemented without prior NRC approval. The WEC departure evaluation packages contained a purpose, scope, assumptions, design basis, codes and standards, reference standards, design methodology, design calculations, drawings, and computer verification data, as applicable. The FPL departure evaluation packages relate to the locations of the operations support center (OSC) and technical support center (TSC). The change to the location of the OSC does not change the manner in which any SSC design functions are performed or controlled. The change of the location of the TSC is a Tier 2* change which requires submittal to the NRC for review. In all cases, the NRC inspection team concluded that the TP AP1000 DCD departures were evaluated in accordance with the requirements of Section VIII of Appendix D to 10 CFR Part 52.

In addition, the NRC inspection team verified that the FPL evaluators and reviewers assigned to review the WEC departure evaluation packages or to develop the FPL departure evaluation packages met the training and qualifications specified in Section 3.3 of FPL NNP-PI-011.

c. Conclusions

The NRC inspection team concluded that the implementation of the FPL and Bechtel design control process is consistent with the regulatory requirements of Criterion III of Appendix B to 10 CFR Part 50. Based on the sample of documents reviewed, the NRC inspection team also concluded that FPL is effectively implementing its policies and associated procedures in support of the COLA for TP Units 6 and 7. No findings of significance were identified.

3. Procurement Document Control

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL procurement document control process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL's procurement document control process to verify compliance with Criterion IV, "Procurement Document Control" of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010
- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010
- BO-AA-102-1008, "Procurement Control," dated March 2, 2010
- QI-4-NSC-1, "Procurement Control," Revision 10, dated January 1, 2011
- QI-4-NSC-9, "Procurement Engineering Control," Revision 2, dated January 6, 2011

- QI-4-NSC-10, "Procurement Engineering Special Quality Assurance Documents (SQADs)," Revision 0A, dated October 28, 2008

In addition, the NRC inspection team the following two purchase orders (POs) to verify proper implementation of FPL's procurement document control program:

- PO 4500395492, "Agreement for Consulting and Design Engineering Services between Florida Power & Light Company and Bechtel Power Corporation for a Development of a Combined License Application," dated November 5, 2007
- PO 4500404639, "Westinghouse Support for Turkey Point Units 6 & 7 COL Application Development," dated May 20, 2008

b. Observations and Findings

b.1 Policies and Procedures

Section B.4, "Procurement Control," of the QATR establishes the measures and governing procedures to ensure that purchased items and services are subject to the appropriate technical, quality, regulatory, and administrative requirements. Applicable technical, regulatory, administrative, quality, and reporting requirements (such as specifications, codes, standards, tests, inspections, special processes, and the requirements of 10 CFR Part 21) are invoked for procurement of items and services.

Section 6.4 of QI-2-NNP-01 states, in part, that NNP commits to the applicable requirements established in Section B.4 of the QATR and procurement of safety-related goods or services will be developed in accordance with QI-4-NSC-1.

BO-AA-102-1008 provides general guidance regarding the control and required responsibilities for the procurement of services and materials.

QI-4-NCS-1 provides specific guidance for the procurement of materials, equipment, and contracted services; as well as controls for corresponding procurement documents.

QI-4-NSC-9 establishes the engineering review, quality, and technical requirements for items and services and ensures that procurement documents clearly identify applicable requirements.

QI-4-NSC-10 provides the requirements and recommendations for the preparation, revision, and issuance of special quality assurance documents (SQADs). SQADs are standardized procurement requirements that are imposed on all procurement documents, as applicable.

The NRC inspection team determined that the documents that control the procurement process provide sufficient guidance to ensure that the necessary technical, quality, regulatory, and administrative requirements are imposed on FPL vendors.

b.2 Implementation of Procurement Document Process

The NRC inspection team reviewed POs 4500395492 and 4500404639, which are associated with the development of the TP Units 6 and 7 COLA, to determine whether the requirements identified in the procedures were imposed on applicable purchasing documents. The NRC inspection team found that the POs adequately documented the procurement requirements as established by the governing policies and procedure. Documentation included task definitions and responsibilities; imposition of appropriate quality, technical, and regulatory requirements; and identification of applicable codes and standards. The NRC inspection team also found that the POs adequately defined contract deliverables, disposition of nonconformances, access rights to sub tier suppliers, and extension of contractual requirements to subcontractors.

In addition, the NRC inspection team confirmed that all of the POs reviewed included clauses invoking the provisions of 10 CFR Part 21 and requiring the vendor to conduct the work under its QA plan related to Appendix B to 10 CFR Part 50.

c. Conclusions

The NRC inspection team concluded that the implementation of the FPL procurement control process is consistent with the regulatory requirements of Criterion IV of Appendix B to 10 CFR Part 50. Based on the sample of documents reviewed, the NRC inspection team also concluded that FPL is effectively implementing its policies and associated procedures in support of the COLA for TP Units 6 and 7. No findings of significance were identified.

4. Document Control

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL document control process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL's document control process to verify compliance with Criterion VI, "Document Control" of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010
- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010.
- AD-AA-100-1004, "Preparation, Revision, Review and Approval of Procedures", Revision 5, dated January 19, 2011
- RM-AA-101, "Control of Documents", Revision 3, dated February 8, 2011
- AD-AA-01, "Document Usage and Administration", Revision 0, dated January 31, 2008

b. Observations and Findings

b.1 Policies and Procedures

Section B.14, "Document Control," of the QATR establishes the measures and governing procedures to specify the format and control the development, review, approval, issue, use, and revision of documents that specify quality requirements or prescribe activities affecting quality or safe operation to ensure the use of correct documents. These measures ensure that specified documents are reviewed for adequacy, approved before use by authorized persons, distributed according to current distribution lists, and used at the location where the prescribed activity takes place. Revisions to controlled documents are reviewed for adequacy and approved for release by the same organization or organizations as originally did so or by other designated organizations that are qualified and sufficiently knowledgeable of the requirements and intent of the original document.

Section 6.6 of QI-2-NNP-01 states, in part, that NNP commits to the applicable requirements established in Section B.4 of the QATR and that procedures will be available at the locations where the activities are conducted. In addition, a controlled index or list of effective pages for controlled documents will be prepared and controlled documents will include a unique identifier (e.g., revision number, amendment number, approval date) to assist the user in determining that the correct version is being used.

AD-AA-100-1004 defines the requirements for document preparation, revision, review and approval of FPL procedures.

RM-AA-101 defines the document control process for FPL controlled documents.

AD-AA-01 establishes the policy for standardizing documentation across the FPL nuclear fleet.

b.2 <u>Implementation of Document Control Process</u>

The NRC inspection team reviewed a representative sample of QA documents and conducted interviews with QA personnel to verify that implementation of the document control processes including approval, issuance, and revisions were consistent with the applicable QA guidance. In general, the document control process is conducted electronically where documents are generated, reviewed, signed, date stamped, and distributed electronically. The approved documents are transmitted using a "read only" format. The NRC inspection team also verified that revisions were reviewed and approved appropriately by the originating organizations, and that superseded documents were recorded in the various records of revisions for each document.

Documents are archived in a records management system where they are made available for retrieval. Recent documents are electronically controlled within the FPL Nuclear Asset Management System (NAMS) database. The NRC inspection team discussed the NAMS database with FPL staff responsible for managing the database. The FPL staff explained the process for document entry and retrieval. The NRC inspection team verified that the FPL staff is adequately managing the NAMS database in accordance with the document control procedures.

c. <u>Conclusions</u>

The NRC inspection team concluded that the implementation of the FPL document control process is consistent with the regulatory requirements of Criterion VI of Appendix B to 10 CFR Part 50. Based on the sample of documents reviewed, the NRC inspection team also concluded that FPL is effectively implementing its policies and associated procedures in support of the COLA for TP Units 6 and 7. No findings of significance were identified.

5. Control of Purchased Equipment, Materials, and Services

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL control of purchased equipment, material and services process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL and Bechtel control of purchased equipment, material and services process to verify compliance with the regulatory requirements of Criterion VII, "Control of Purchased Equipment, Material, and Services" of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, October 22, 2010
- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010.
- QI 7 QAD 4, "Supplier Review," Revision 35, dated July 30, 2009
- QI 7 QAD 5, "Establishing and Maintaining the Qualified Suppliers List," Revision 29, dated July 30, 2009
- QI 7 QAD 6, "Methods for Supplier Evaluation," Revision 35, dated July 30, 2009
- QI 10 QAD 1, "Surveillances," Revision 4, dated December 1, 2008
- QI 16 QAD 3, "Controlling Supplier Open Items," Revision 33, dated February 12, 2010
- QI 18 QAD 11, "Evaluation of Supplier Audit Reports Received From External Organizations," Revision 20, dated July 30, 2009
- NNP-PI-04, "COLA Configuration Control and Responses to Requests for Additional Information for Project Applications," Revision 2, dated September 10, 2010
- NNP-PI-08, "COLA Review and Acceptance Process," Revision 4, dated September 10, 2010
- NA-AA-203-1000, "Performance of Nuclear Oversight Audits," Revision 2, dated November 8, 2010
- 2011 Supplier Evaluation Annual Plan, dated February 24, 2011
- Bechtel Nuclear Quality Assurance Manual, Revision 4, dated November 11, 2002
- Florida Power & Light Company, Turkey Point Combined Operating License Project, Bechtel Job No. 25409, Quality Assurance Program Plan, Revision 1, dated June 8, 2009

In addition, the NRC inspection team reviewed the following audits performed during the preparation of the TP Units 6 and 7 COLA:

- Southern California Edison Audit No. BPC-1-08, NUPIC Joint Utility Audit No. 20084 of Bechtel Power Corporation; and Corrective Action Request No. S-1993, dated April 4, 2008 (audit performed March 3-7, 2008)

- South Texas Project Nuclear Operating Company Quality Audit of Bechtel Power Corporation - Audit No. 10-067 (VA), dated November 17, 2010 (audit performed October 25-28, 2010)

- FPL Audit PQA 10-173 using an Audit/Survey Report Review Checklist, dated January 20, 2011

- NUPIC Limited Scope Audit of Nuclear Power Plants U.S. AP1000 Project Activities, PGN Audit QAA/0300-10-01, NUPIC Audit No.: 22766, dated October 27, 2010 (audit performed September 27 - October 1, 2010)

- FPL/FPLE QA Surveillance Report – Report No. 08.06.BEPMD.08.3, dated July 15-16, 2008

- FPL/FPLE QA Surveillance Report – Report No. 08.06.BEPMD.08.4, dated September 29, 2008
- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSSS-08-001, dated February 20, 2008 (audit performed February 12, 2008)

- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSSS-08-002, dated March 4, 2008 (audit performed February 25-27, 2008)

- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSSS-08-003, dated April 9, 2008 (audit performed March 18, 2008)

- FPL Turkey Point COL Project QA Surveillance No. 25409-QSSS-08-001 Follow-up, dated April 3, 2008 (File No. 25409-000-IOM-GAP-00003)

- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSVS-08-002, dated May 7, 2008 (audit performed April 14-15, 2008)

- FPL Turkey Point COL Project QA Surveillance No. 25409-QSVS-08-002 Follow-up, dated July 25, 2008 (File No. 25409-000-IOM-GAP-00011)

- Supplier Audit Report MACTEC Engineering & Consulting, Raleigh, NC – Report No. ESL-2008-007, Revision 1, dated January 2, 2009 (audit performed October 21 - 24, 2008)

- Supplier Audit Report MACTEC Engineering & Consulting, Raleigh, NC – Report No. 2009-ESL-005, dated June 19, 2009 (audit performed May 19 - 20, 2009)

- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSVS-08-001, dated April 10, 2008 (audit performed March 14, 2008)

b. Observations and Findings

b.1 Policies and Procedures for Vendor Qualification

Sections B.4 and B.5, "Procurement Verification," of the QATR establishes the requirements for the evaluation of prospective suppliers of safety-related items and services to ensure that only qualified suppliers are used. Qualified suppliers are periodically evaluated to ensure that they continue to provide acceptable products and services. The results of the reviews are promptly considered for their effect on a supplier's continued qualification, and adjustments are made as necessary (including corrective actions, adjustments of supplier audit plans, and input to third-party auditing entities, as warranted). In addition, results are reviewed periodically to determine if, as a whole, they constitute a significant condition adverse to quality requiring additional action. Measures are also established and implemented to verify the quality of purchased items and services, whether purchased directly or through contractors, at intervals and to a depth consistent with the item's or service's importance to safety, complexity, quantity, and the frequency of procurement.

Section 6.7 of QI-2-NNP-01 establishes the measures and governing procedures to control the procurement of items and services associated with the TP Units 6 and 7 COLA to ensure conformance with specified requirements. The NRC inspection team noted that FPL's control of procurement of items and services consisted of the maintenance of a qualified suppliers list (QSL), periodic evaluation of qualified suppliers, activities to verify quality, audits, and examination of items and services.

QI 7 QAD 5 delineates the responsibilities and requirements for establishing and maintaining the FPL QSL. The procedure also applies to the establishment, maintenance, and control of commercial grade suppliers and augmented quality suppliers as applicable based on specific requirements for supplier control.

QI 7 QAD 6 delineates the methods by which the nuclear oversight organization evaluates and approves the suppliers of items or services that are to be procured for nuclear power plants, and is applicable to all items or services that are designated as safety related, commercial grade requiring an approved supplier, or augmented quality.

QI 18 QAD 11 provides instructions for the evaluation of supplier audit and commercial grade survey reports received from the Nuclear Procurement Issues Committee (NUPIC), the American Society of Mechanical Engineers (ASME), individual nuclear utilities, and other FPL/NEE approved organizations.

b.2 Maintenance of the Qualified Suppliers List

Section B.4 of the QATR, Section 6.7 of QI-2-NNP-01, and QI 7 QAD 5 define the controls for the establishment, maintenance, distribution, and update of the QSL. The procedures state that the appropriate group within the nuclear oversight organization has the responsibility for preparing, approving, maintaining current, and distributing the QSL and any revisions to this list. When a QSL change is made requiring the performance of an audit and surveillance during the supplier's onsite activities, the nuclear oversight organization is responsible for notifying the affected parties, as well as ensuring that a condition report (CR) is initiated in the event that a QSL change is prompted by the discovery of supplier deficiencies that might adversely impact items and services on order or previously delivered.

The NRC inspection team verified that the QSL was kept up to date and that any revision to the list was implemented in accordance with the applicable procedures.

b.3 External Audits

NA-AA-203-1000 and QI 7 QAD 6 establishes the requirements and methods for implementation of the program for performing supplier audits and surveillances, including the actions to be taken to address and follow up on any findings identified. FPL conducts audits at a supplier's facility to verify implementation of in-process activities and acceptability of the written QAP and procedures in order to reach conclusions about whether items produced under the supplier's processes will perform their intended functions.

At the time of this inspection, Bechtel was the prime contractor with retained responsibility for development of the TP Units 6 and 7 COLA. Bechtel maintained responsibility for the qualification and oversight of its subcontractors and suppliers (such as MACTEC and ABSG Consulting). FPL plans to complete the TP Units 6 and 7 COLA project using the application developed by Bechtel in conjunction with AP1000 design services from WEC, as necessary.

The NRC inspection team reviewed a sample of external audits and supplier evaluations conducted by both FPL and Bechtel to verify adequate implementation of the respective audit programs. The NRC inspection team verified that audit plans identifying the audit scope, focus, and applicable checklist criteria had been prepared and approved before the initiation of the audit activity. The NRC inspection team also verified that the checklists were prepared and completed for the audit and contained sufficient objective evidence to support the conclusions made by the auditors. In addition, the NRC inspection team verified that external audits were performed by qualified lead auditors and auditors. For audits and surveillances resulting in findings, the NRC inspection team verified that the supplier had established a plan for corrective actions and that FPL and Bechtel had verified its satisfactory completion and proper documentation.

For supplier audits or surveys conducted by organizations external to FPL, such as NUPIC, ASME, individual nuclear utilities, and other FPL/NEE-approved organizations, the NRC inspection team verified that FPL had reviewed, accepted, and appropriately dispositioned any findings evaluations performed by these external organizations, in accordance with QI 18 QAD 11.

b.4 Combined License Application Review and Acceptance Process

NNP-PI-08 and NNP-PI-04 provide: (1) the administrative requirements for the review of the COLA from the initial draft through final FPL acceptance of the initial application; (2) updates to the COLA either annually or more frequently if necessary; and (3) the administrative requirements for maintaining the configuration of the COLA during the post submittal review process.

These procedures establish the review guidelines to be utilized by the licensing review board (LRB) as a part of its evaluation and acceptance of various work products related to the TP Units 6 and 7 COLA. The LRB consists of FPL licensing and engineering personnel, COLA contractor personnel, and others as required to review COLA chapters for completeness and sufficiency for submittal to the NRC.

The NRC inspection team reviewed the documentation associated with the acceptance of various COLA sections, integrated chapters, and revisions via the applicable LRB meeting determinations, and verified that FPL is adequately implementing the COLA review and acceptance process outlined above.

c. Conclusions

The NRC inspection team concluded that the implementation of FPL's control of purchased equipment, materials, and services process is consistent with the regulatory requirements of Criterion VII of Appendix B to 10 CFR Part 50. Based on the sample of documents reviewed, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

6. Corrective Actions

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL corrective action program (CAP) in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL's CAP to verify compliance with the regulatory requirements of Criterion XVI, "Corrective Action," of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010
- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010
- ENG-QI 2.5, "Condition Reports," Revision 24, dated July 10, 2010
- PI-AA-204, "Condition Identification and Screening Process," Revision 10, dated August 30, 2010
- PI-AA-205: "Condition Evaluation and Corrective Action," Revision 10, dated November 8, 2010
- NPP-PI-07, "Department Training," Revision 2, dated August 16, 2010
- WM-AA-201, "Work Order Identification, Screening and Validation Process," Revision 6, dated July 10, 2010

In addition, the NRC inspection team reviewed a sample of AR reports (listed below), attended Initial Screening Team (IST) and Management Review Committee (MRC) meetings, and discussed the program with responsible FPL personnel.

- Action Request Number 01605884, "Nustart Identified Editorial Error RCOLA NRC Submittal, " dated January 5, 2011
- Action Request Number 01605421, "PTN 6 & 7 Error in Lag Time Value in HEC-HMS Model," dated January 4, 2011
- Action Request Number 00586866, "Processing of Potential or Reported 10 CFR 21 Issues," dated October 13, 2010
- Action Request Number 00465189,"The New Nuclear Project (NNP) is Using the Nuclear Division Correction Process," dated May 17, 2009
- Action Request 00477542, "Control of RAI, RFI, and NRC Correspondence QA Records," dated May 11, 2010
- Action Request Number 01625226, "Part 21 Process Ties Include Various Procedures & Department", dated March 2, 2011
- Action Request Number 00586866, "Processing of Potential or Reported 10 CFR 21 Issues," dated October 13, 2010
- Action Request Number 01625947, "PTN 6 & 7 COLA QA Records Not Transmitted in a Timely Manner," dated March 3, 2011
- Action Request Number 01620241, "PTN 6 & 7 NNP-PI-03 Procedural Issues for Records Storage," dated February 15, 2011
- Action Request Number 01612149, "Unites 6/7 QA Records Storage at PTN Administrative Issues," dated January 25, 2011
- Action Request Number 01622965, "New Plant OE - Part 21 Reporting Procedure," dated February 23, 2011
- Management Review Committee Agenda for March 3, 2011
- Initial Screening Team Agenda for March 2, 2011

b. <u>Observations and Findings</u>

b.1 <u>Policies and Procedures</u>

Section A.6 of the QATR states, in part, that the CAP is implemented to promptly identify, control, document, classify, and correct conditions adverse to quality. In addition, for significant conditions adverse to quality, the program provides for cause evaluation and corrective actions to prevent recurrence. Provisions are also made to ensure that corrective actions for significant conditions adverse to quality are completed as intended and are not inadvertently nullified by subsequent actions. Results of evaluations of conditions adverse to quality are analyzed to identify trends. Significant conditions adverse to quality and significant adverse trends are documented and reported to responsible management.

Section 6.16 of QI-2-NNP-01 states, in part, that NNP commits to the applicable requirements established in the NEE QATR, Section B.13, "Corrective Action," and that the implementation of the NEE CAP shall be as specified in procedures PI-AA-204 and PI-AA-205. The MRC screens conditions for 10 CFR Part 21 applicability in accordance with procedure PI-AA-204 to determine significance level, prioritization, issue ownership, and required action.

PI-AA-204 defines the processes for identifying, screening, and documenting unexpected or unwarranted conditions. It describes actions required for personnel direction and establishes roles and responsibilities for initiating and screening condition reports. Step 4.1 states that personnel should correct any identified condition to the extent possible as soon as practical. PI-AA-205 provides direction for using the condition reporting process to investigate and take appropriate corrective actions to address undesirable conditions. Step 4.9.1 stats that, in part, that closer of corrective actions in not permitted until corrective actions are completed as prescribed.

ENG-QI 2.6 provides instructions for the initial assessment, evaluation, and processing of CRs assigned to engineering. Section 5.5.3, which discusses the evaluation and documentation of corrective actions, states, in part, that a 10 CFR SSH evaluation is required only if a basic component is involved and a defect or noncompliance with regulations is involved.

WM-AA-201 provides the work control process for identifying, screening, and validating work requests. Step 3 in Section 4.0 of WM-AA-201 states, in part, that all site personnel are expected to initiate action requests for identified deficiencies related to plant equipment or facilities. There was no link between this procedure and PI-AA-04, PI-AA-205, or a 10 CFR Part 21 procedure.

PI-JB-1000 provides guidance for screening action requests, completing assignments, and obtaining MRC reviews of evaluations.

The NRC inspection team noted that although QI-2-NNP-01 states that conditions are screened for 10 CFR 21 applicability per procedure PI-AA-204, actual procedural guidance for 10 CFR Part 21 screening was not contained in this procedure. Additionally, PI-AA-204 and PI-AA-205 provided no procedural connection to ENG-QI-2.5, WM-AA-201, and PI-JB-1000. These procedures provide detailed instructions for initial assessment, screening, and evaluation of condition reports that are not included in PI-AA-204 and PI-AA-205. The NRC inspection team identified that the lack of procedural guidance in PI-AA-204 and PI-AA-205 was not in accordance with the QI-2-NNP-01.

b.2 <u>Implementation of Corrective Action Program</u>

While reviewing a sample of AR reports, the NRC inspection team noted that FPL failed to identify deviations and screen conditions for 10 CFR Part 21 applicability, as described in Section 6.15 of QI-2-NNP-01. Specifically, the AR forms documented the unidentified and unwarranted conditions, but failed to label the unidentified and unwarranted conditions as deviations. Additionally, the AR reports contained a box to identify whether 10 CFR Part 21 applied to identified conditions, but FPL lacked procedural guidance in PI-AA-204 and PI-AA-205 to determine whether the Part 21 box applied to the identification of a deviation or an issue with FPL's Part 21 program. For example, in AR 01622965, conditions identified as dealing with FPL's Part 21 program were inconsistently screened as applying to 10 CFR Part 21. The NRC inspection team concluded that the lack of adequate procedural guidance resulted in inadequate implementation of FPL's CAP. The NRC inspection team identified this issue as an example of Violations 05200040/2011-201-02 and 05200041/2011-201-02.

The NRC inspection team also noted that FPL failed to correct conditions adverse to quality in an adequate and timely manner, as described in PI-AA-205. Specifically, in AR 00477542, FPL identified a condition adverse to quality regarding the storage of QA records. This condition adverse to quality was screened by the IST and MRC and then closed. The NRC inspection team identified that this issue was not corrected in accordance with PI-AA-205, given that the discovery of QA record management issues that were previously addressed in AR 0477542 still existed. The NRC inspection team identified this issue as another example of Violations 05200040/2011-201-02 and 05200041/2011-201-02.

c. Conclusions

The NRC inspection team concluded that FPL is not implementing its Corrective Action Program consistent with the requirements of Criterion XVI, "Corrective Action," of Appendix B to 10 CFR Part 50. The NRC inspection team issued Violations 05200040/2011-201-02 and 05200041/2011-201-02 for FPL's failure to establish measures to ensure conditions adverse to quality, such as deviations and nonconformances are promptly identified and corrected. Specifically, FPL failed to promptly correct nonconformances identified in closed Action Request 00477542, "Control of RAI, RFI, and NRC Correspondence QA Records," dated May 11, 2010. In addition, FPL failed to correctly identify and document the existence of deviations in AR 01622965.

7. Audits

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL and Bechtel audits process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL's audits process to verify compliance with Criterion XVIII, "Audits," of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010

- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of the PTN 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010

- NA-AA-203-1000, "Performance of Nuclear Oversight Audits," Revision 2, dated November 8, 2010

- NA-AA-202-1000, "Audit Topic Selection and Scheduling," Revision 2, dated October 28, 2010

- NA-AA-204-1000, "Findings," Revision 2, dated November 8, 2010

- NA-AA-207-1000, "Auditor Qualification and Certification," Revision 0, dated February 7, 2011
- Bechtel Nuclear Quality Assurance Manual, Revision 4, dated November 11, 2002
- Florida Power & Light Company, Turkey Point Combined Operating License Project, Bechtel Job No. 25409, Quality Assurance Program Plan, Revision 1, dated June 8, 2009

In addition, the NRC inspection team selected the following internal audits performed during the preparation of the TP Units 6 and 7 COLA for review:

- Turkey Point Nuclear Oversight Report – New Nuclear Projects Programs and Licensing Audit – Report No. PTN-10-011, dated May 17, 2010 (audit performed April 1-2, 2010)
- Review of New Nuclear Project Quality Assurance Plan for Conformance to NRC Requirements – Quick Hit Report No. 2009-15001, dated May 17, 2009 (audit performed April 28-29, 2009)
- Juno Beach Nuclear Assurance Quality Report – New Plant Procurement Activities – Report No. 08-001, dated March 28, 2008
- FPL/NextEra Energy Nuclear Oversight Surveillance Report – Report No. PQA 10-106, dated April 8, 2010
- Bechtel Quality Surveillance Report, Surveillance No. 25409-QSHS-09-002, dated May 28, 2009 (audit performed May 19-21, 2009)

b. Observations and Findings

b.1 Policies and Procedures

Section C, "Assessments," of the QATR establishes requirements for a program of planned and periodic performance-based independent assessments to monitor overall performance and confirm that activities affecting quality comply with the QAP and that the QAP is effectively implemented. This program is, itself, reviewed for effectiveness as part of the overall assessment process. Both self-assessments and independent assessments are accomplished using instructions or procedures that provide detail commensurate with the assessed activity's complexity and importance to safety.

Section 6.18 of QI-2-NNP-01 states, in part, that NNP commits to the applicable requirements established in Section C of the QATR and that audits and surveillances will be conducted of suppliers on the NEE QSL and internal NEE activities, with surveillance activities conducted on sub tier suppliers.

NA-AA-202-1000 provides instructions for selecting and scheduling topics for NO audits. Audit topic selection is performed in accordance with requirements in the QATR using either the fixed schedule or the flexible scheduling process. This procedure also ensures that: (1) applicable elements of the QAP are audited at least once every two years or once within the life of an activity requiring oversight, whichever time is the shortest; and (2) audits of selected operational phase activities are performed at a frequency commensurate with safety significance and performance.

NA-AA-204-1000 provides detailed information for the identification, documentation, transmittal, and follow up of findings identified by nuclear oversight personnel. This procedure applies to findings identified during audits, surveillances, or technical reviews performed by the nuclear oversight organization. This procedure also establishes that nuclear oversight personnel are responsible for identifying and documenting conditions adverse to quality, conditions not adverse to quality, and significant conditions adverse to quality during the performance of oversight activities, such as audits, technical reviews, and routine surveillances.

b.2 Internal Audits

FPL established an internal audit program under Section C of the QATR, as implemented by NA-AA-203-1000. This procedure provides general timeliness requirements for the conduct of audits and identifies requirements for audit team composition and qualifications. It also provides guidance for preparing audit plans, making audit notifications, assembling audit checklists, performing audits, and reporting conditions potentially adverse to quality, as well as for audit closeout and documentation. NA-AA-203-1000 also refers to NA-AA-202-1000 for guidance on audit topic selection and scheduling.

The NRC inspection team reviewed a sample of internal audit reports performed in support of the TP Units 6 and 7 COLA to verify that internal audits were performed in accordance with program requirements. For each of the audits reviewed, the NRC inspection team verified that the audit reports identified audit findings and corrective actions associated with these findings. The NRC inspection team also verified that audits were conducted using a checklist to ensure that all applicable regulatory and quality requirements and criteria were evaluated. The checklists contained an adequate level of objective evidence to support the classification of checklist criteria as satisfactory or unsatisfactory. The NRC inspection team noted that corrective actions were taken promptly to respond to any identified findings and the reports contained an adequate level of objective evidence to support closing of the condition. The NRC inspection team also verified that the audit plan identifying the audit scope, focus, and applicable criteria had been prepared and approved before initiation of the audit or surveillance activity.

The NRC inspection team verified that FPL had established a 2011 audit and surveillance schedule which included all functional areas currently being performed by FPL or Bechtel in relation to the TP Units 6 and 7 COLA, along with the applicable quality criteria from Appendix B to 10 CFR Part 50. The 2011 audit and surveillance schedule meets the frequency requirements delineated in the QATR and associated implementing procedures.

b.3 Auditor Training and Qualification

NA-AA-207-1000 establishes the requirements for the qualification and certification of auditors and lead auditors. The NRC inspection team reviewed a sample of lead auditor and auditor qualifications and training records and confirmed that auditing personnel had completed all required training and maintained qualification and certification in accordance with FPL's policies and procedures. The NRC inspection team also verified that audit teams selected by FPL were sufficiently qualified to evaluate areas within the scope of the audit and that the auditors were not auditing their own work.

c. Conclusions

The NRC inspection team concluded that the implementation of FPL's internal audit process is consistent with the regulatory requirements of Criterion XVIII, "Audits," of Appendix B to 10 CFR Part 50. Based on the sample of documents reviewed, the NRC inspection team determined that FPL is effectively implementing its policies and procedures in support of the TP Units 6 and 7 COLA. No findings of significance were identified.

8. Quality Assurance Records

a. Inspection Scope

The NRC inspection team reviewed the implementation of the FPL QA records process in support of the COLA for TP Units 6 and 7. Specifically, the NRC inspection team reviewed the policies and procedures governing the implementation of FPL's QA records process to verify compliance with Criterion XVII, "Quality Assurance Records," of Appendix B to 10 CFR Part 50.

The NRC inspection team reviewed the following documents for this inspection area:

- Florida Power & Light Company, NextEra Energy Seabrook, LLC, NextEra Energy Duane Arnold, LLC, and NextEra Energy Point Beach, LLC, "Quality Assurance Topical Report," FPL-1, Revision 8, dated October 22, 2010
- QI-2-NNP-01, "Quality Assurance During the Pre-Construction Phase of PTN the 6 & 7 New Nuclear Project," Revision 2, dated November 1, 2010
- NNP-PI-03, "Project Document Retention," Revision 1, dated September 10, 2010
- QI 17-PTN-1, "Quality Assurance Records," Revision 2, dated October 11, 2010
- QI 17-NSC-1, "Quality Assurance Records," Revision 5A, dated February 11, 2008

b. Observations and Findings

b.1 Policies and Procedures

Section B.15, "Records," of the QATR establishes the measures and governing procedures to ensure that sufficient records of items and activities affecting quality are generated and maintained to reflect completed work. Such records may include, but are not limited to, design, engineering, procurement, manufacturing, construction, inspection, test, installation, modification, operations, maintenance, corrective action, assessment, and associated reviews. The provisions establish requirements for records administration, including generation, receipt, preservation, storage, safekeeping, retrieval, and final disposition.

Section 6.18 of QI-2-NNP-01 states, in part, that NNP commits to the applicable requirements established in Section B.15 of the QATR. Records shall be maintained that support the achievement of quality on all project activities. QA records will be processed in accordance with QI 17-PTN-1, with the TP site as the current long-term storage and control location.

NNP-PI-03 states, in part, that records associated with the preparation of the COLA and the NRC review and approval of the COLA shall be retained for the life of the plant.

QI 17-PTN-1 states, in part, that sufficient records shall be maintained to furnish documentary evidence of the quality of safety-related SSCs and that QA records should be transmitted to site document control within 30 days after completion, unless approved otherwise by the site document control supervisor. Additionally, QI 17-PTN-1 establishes the requirements for managing and transferring controlled documents into the official records management system (RMS). It specifies Lotus Notes as the RMS for listing and tracking QA records and specifies Turkey Point Nuclear Plant as the data entry point and storage facility. QI 17-PTN-1 emphasizes FPL's commitment to the guidance of NRC Regulatory Guide 1.28, Revision 3, "Quality Assurance Program Criteria (Design and Construction)," issued August 1985.

QI 17-NSC-1 states, in part, that this procedure provides requirements and guidance regarding the generation, transmittal, processing, and retention of QA records and describes the interfaces between the nuclear supply chain and the records management organization.

b.2 Implementation of Quality Assurance Records Process

The NRC inspection team reviewed a sample of several records, including training records and TP AP1000 DCD departure packages. The NRC inspection team also conducted interviews with FPL's staff and management responsible for the implementation of the QA records process. During this review, the NRC inspection team verified that FPL had implemented a QA records process for the administration, identification, receipt, storage, preservation, safekeeping, and disposition of records. The NRC inspection team also verified that the FPL RMS had the capacity to maintain the integrity, authenticity, and acceptability of QA records during the required retention period.

During the review of the training records and TP AP1000 DCD departure packages, the NRC inspection team noted that these records were not being maintained in accordance with QI 17-PTN-1. Specifically, these records were being maintained in temporary storage for longer than 30 days (in excess of 19 months) instead of being forwarded to the long term storage facility within 30 days of issuance as required by the procedure. The NRC inspection team identified this issue as an example of Violations 05200040/2011-201-02 and 05200041/2011-201-02 for FPL's failure to correct conditions adverse to quality in an adequate and timely manner as previously described in Section 6.b.2 above.

c. Conclusions

With the exception of Violations 05200040/2011-201-02 and 05200041/2011-201-02 in relation to FPL's failure to correct conditions adverse to quality associated with storage of QA records in an adequate and timely manner, the NRC inspection team concluded that the implementation of FPL's QA records program is consistent with the regulatory requirements of Criterion XVII, "Quality Assurance Records," of Appendix B to 10 CFR Part 50.

Entrance and Exit Meetings

On February 28, 2011, the NRC inspection team presented the inspection scope during an entrance meeting with Mr. Bill Maher, Senior Director for Licensing, and other FPL and Bechtel personnel. On March 4, 2011, the NRC inspection team presented the inspection results during an exit meeting with Mr. Bill Maher, and other FPL and Bechtel personnel.

1. PERSONS CONTACTED

NAME	COMPANY	TITLE	ENTRANCE MEETING	EXIT MEETING	INTERVIEWED
Bill Maher	FPL	New Nuclear Projects Licensing Senior Director	√	√	√
Steve Franzone	FPL	New Nuclear Projects Licensing Manager	√	√	√
Rich Weiss	FPL	QA Supervisor	√	√	√
Shiela Schlafly	FPL	Principal Quality Engineer			√
George Madden	FPL	Licensing Engineer	√		√
Ray Burski	FPL	Licensing Engineer	√	√	√
Rick Orthen	FPL	Licensing Engineer	√	√	
Tom Childress	FPL	Licensing Engineer	√	√	
Joeri Carty	FPL	Standardization Manager			√
Jim Connolly	FPL	Fleet Licensing Manager	√	√	
Paul Jacobs	FPL	Engineering Supervisor	√	√	
Basil Pagnozzi	FPL	Engineering Chief Staff	√	√	
Wallace Woodward	FPL	Nuclear Assurance	√		
Dominick Fuca	FPL	Manager Performance Assessment	√	√	√
Pete Wells	FPL	VP Organizational Support	√		
Jennifer Schaffer	FPL	Performance Improvement Trending Coordinator			√
Tom Rohe	FPL	Performance Improvement			√
Elizabeth Paine	FPL	Administrative Support	√		
Raj Jolly	Bechtel	Project QA Manager	√	√	√
John Cunliffe	Bechtel	Project Manager	√	√	
Bob Yamrus	Bechtel	Project Engineer	√		
Yamir Diaz-Castillo	NRC	Inspection Team Leader	√	√	
NAME	COMPANY	TITLE	ENTRANCE MEETING	EXIT MEETING	INTERVIEWED

NAME	COMPANY	TITLE	ENTRANCE MEETING	EXIT MEETING	INTERVIEWED
Kerri Kavanagh	NRC	Inspector	√	√	
Stacy Smith	NRC	Inspector	√	√	
Marlayna Vaaler	NRC	Inspector	√	√	
Brent Clarke	NRC	Inspector	√	√	
Manny Comar	NRC	NRC Senior Project Manager	√		

2. INSPECTION PROCEDURES USED

Inspection Procedure 35017, "Quality Assurance Implementation Inspection," dated July 29, 2008.

Inspection Procedure 36100, "Inspection of 10 CFR Part 21 and 50.55(e) Programs for Reporting Defects and Noncompliance," dated October 3, 2007.

3. LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

The NRC had not performed any previous implementation inspections of the QA program governing the COLA for TP Units 6 and 7.

Item Number	Status	Type	Description
05200040/2011-201-01	Opened	NOV	Violation of Part 21
05200041/2011-201-01	Opened	NOV	Violation of Part 21
05200040/2011-201-02	Opened	NOV	Criterion XVI
05200041/2011-201-02	Opened	NOV	Criterion XVI

4. LIST OF ACRONYMS USED

AR	action request
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CFR	*Code of Federal Regulations*
COLA	combined license application
CR	condition report
DCD	design control document
FPL	Florida Power & Light
FSAR	final safety analysis report
IP	inspection procedure
IST	Initial Screening Team
LRB	licensing review board
MRC	Management Review Committee
NAMS	Nuclear Asset Management System
NEE	NextEra Energy

NNP	New Nuclear Project
NO	nuclear oversight
NUPIC	Nuclear Utilities Procurement Industry Committee
NRC	U.S. Nuclear Regulatory Commission
OSC	operations support center
PO	purchase order
QA	quality assurance
QAP	quality assurance program
QATR	quality assurance topical report
OSC	operations support center
QSL	qualified suppliers list
RMS	records management system
SQAD	special quality assurance document
SSC	structure, system, and component
SSH	substantial safety hazard
TP	Turkey Point
TSC	technical support center
WEC	Westinghouse Electric Company

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___
Witness: Robert E. Barrett, Jr., Renae B. Deaton, Joseph A. Ender, Kim Ousdahl, Dr. Rosemary Morley

Line No. (1)

INDEX AND LIST OF ATTACHMENTS

List of Attachments to Minimum Filing Requirement (MFR) Schedule F-5

Attachment Number	OVERVIEW
01	Flowchart: Forecasting process overview
02	Document: Load Forecasting Methodology
03	Flowchart: Forecast customer model
04	Flowchart: Net energy for load model
05	Flowchart: Sales by customer class
06	Flowchart: Modeling summer and winter peaks
07	Flowchart: Consolidated Financial Model
08	Document: Annual planning process guideline
09	Document: Calendar for management review meetings and submittal of deliverables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

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I. OVERVIEW OF THE FORECASTING PROCESS

FPL's forecasting process starts with the generation of projected data for each of the major categories of inputs in order to determine the projected financial results:

- Forecast of Sales, NEL and Peak Demand — developed by the Load Forecasting section of the Finance Department using econometric models.
- Forecast of Generation Power Supply and Fuel Expense - developed by Resource Assessment and Planning (RAP) using the P-MArea forecasting model.
- Forecast of Base Revenues — developed by the Rates and Tariff Department
- Forecast of O&M Expense — developed by each Business Unit.
- Forecast of Capital Expenditures — developed by each Business Unit.

These forecasts, along with supplemental forecasts of other items such as property taxes, commercial paper rates, etc., are inputs to FPL's Consolidated Financial Model (CFM, MFR F-05 Attachment 07), which performs certain calculations and generates summary level projected financial statements. The CFM's financial plan is regularly used by FPL's management for decision making and performance assessment. It is not, however, sufficiently detailed to provide all the data reflected in the Minimum Filing Requirements (MFRs). For that purpose, FPL has developed the Regulatory Information System (RIS), which consolidates data from the CFM and other sources in order to generate at a detailed level the jurisdictional adjusted rate base, net operating income and capital structure. The RIS outputs, in turn, support the calculation of total company revenue requirements and support the preparation of the company's jurisdictional separation and cost of service studies.

MFR F-05 Attachment 01 shows the flow of information among the various models and modules that comprise FPL's forecasting process.

In developing data for 2012 and 2013, actual data for the period ended September 30, 2011 was used as the starting point. 'Projected data for the last three months of 2011 and for all of 2012 and 2013 was then developed.

Supporting Schedules: Recap Schedules:

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II. SALES, NEL AND PEAK DEMAND

The Forecasting section of the Finance Department uses econometric models to project customers, energy sales, net energy for load and peaks. Forecasts for 2012 and 2013 are developed on a monthly basis for customers, net energy for load (NEL), sales, and peaks. Customers and sales are developed by revenue class. In compliance with the filing request pertaining to this MFR, a detailed description of the forecasting methodology for these items will be provided under separate cover. See, MFR F-5 Attachments 02, 03, 04, 05, and 06.

III. GENERATION POWER SUPPLY AND FUEL EXPENSE

The RAP Department develops the resource plan to meet FPL's resource needs. Load data, fuel prices, plant operating parameters, plant outage schedules, Demand Side Management (DSM) program data, qualifying facilities and interchange projections are all entered into the P-MArea model. This model then generates an electric production cost forecast that includes Megawatt Hours (MWH) produced, wholesale sales and purchases and fuel expense.

IV. BASE REVENUES

Retail Base and Wholesale Base Revenue forecasts are developed by the Rates and Tariff Department for each customer class. For the years 2012 and 2013, retail base revenues are forecasted based on a projection of billing determinants by rate class. The methodology for developing projected billing determinants is described in MFR E-15. Projected billing determinants by rate class are then applied against the currently approved tariff charges to obtain a forecast of base revenues by rate class. Base revenues by customer class are then determined based on the historical relationships between revenues by rate schedule and revenues by rate class. 'For the year 2013, retail base revenues are forecasted by projecting the cents per kWh for base revenues by rate class and applying the results to the forecasted sales by rate class. For the year 2013, wholesale base revenues are forecasted by applying projected billing determinants to wholesale base rates by rate schedule and/or contract.

Supporting Schedules: Recap Schedules:

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V. O&M EXPENSE FORECAST

The Operation and Maintenance (O&M) forecasts were prepared using the same basic process employed by the company since the early 1990's.

At the beginning of the annual planning process, the FPL Corporate Budgets department issues the following materials to the FPL business units (see MFR F-05 attachments 08 and 09):

- § annual planning process guideline
- § calendar for management review meetings and submittal of deliverables

The planning process requires each operating business unit to provide a year-end estimate for its current year budget (2011 in this instance), and identify its required funding levels for the next three years (2012, 2013, and 2014). The units must also identify the drivers of any expected variance from the current year's plan, as well as any increase or decrease in the level of funding required for each of the forecasted years.

During the scheduled management review meetings, each participating business unit head is available to make a presentation, if requested, to the Budget Review Committee, key members of which are the FPL Chief Executive Officer and President; the FPL Senior Vice President, Finance and Chief Financial Officer; FPL Vice President Finance; and the FPL Vice President Controller and Chief Accounting Officer. During the presentation, the business unit head explains his or her unit's goals, objectives and key initiatives, and the associated forecasted funding requirements. The Budget Review Committee is responsible for reviewing and approving the forecasts to ensure reasonableness and completeness for budget planning purposes.

The approved 2012 O&M expense budget and the approved 2013 O&M expense forecast were used to prepare the Minimum Filing Requirements.

VI. CAPITAL EXPENDITURES FORECAST

The annual capital forecasting process is the same as the O&M expense forecasting process. The processes are performed concurrently. See the previous section (V. O&M Expense Forecast) for a discussion of the forecast development methodology and the review and approval process.

To satisfy the special information requirements of the Consolidated Financial Model, the capital forecast is extended to include five years (through 2016 in this instance).

Supporting Schedules: Recap Schedules:

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When developing its five year capital forecast, each business unit must classify its capital investments by project. Projects must be classified as either major or minor. Major projects are those with a total cost over the life of the project of more than $10,000,000 and which have a specific in service date. Capital investments that do not meet the criteria for a major project are grouped under one or more minor projects at the business unit's discretion. All major and minor projects must be further defined by FERC function, and a plant site code, if applicable. All projects also must indicate the anticipated recovery mechanism, either through base rates or a clause. Additional administrative requirements of the Financial Forecasting Model are included in the annual planning process guideline (see MFR F-05 attachment 08).

The approved 2012 capital budget and the approved 2013 capital forecast were used to prepare the Minimum Filing Requirements.

VII. CONSOLIDATED FINANCIAL MODEL

A. SYSTEM OVERVIEW

In developing data for the 2013 test year, actual data for the period ended September 30, 2011 was used as a base for the forecast. Projected data for the last three months of 2011 and for all of 2012 and 2013 was then developed.

The corporate modeling system used by the Finance Department was created by Utilities International, Inc. Financial Planner (FP) is an integrated financial planning model used to consolidate FPL's forecasted financial data for reporting to management and external parties.

FP design uses a module-based structure in which the Consolidated Financial Module (CFM) serves as a central collection point for all of FP's feeder calculations. Feeder calculations consist of, Electric Sales and Revenues, O&M expenses, Construction and Plant Accounting inputs, Long-Term Financing inputs and User inputs. CFM calculations are made using Java code in the model. The CFM calculations result in journal entries to a ledger chart of accounts which are rolled up to generate financial statements for the Company.

For data inputs that do not fall into one of the modules listed below, the CFM allows for the inputs to be forecasted outside of the model and manually input into the CFM module for calculations or journal entries.

Additionally, in certain instances where values for miscellaneous items are not specifically forecasted, either as a manual input, or through another module, the CFM applies a standardized forecast method to forecast future periods. An example of one of the standard methods used is "most recent balance of corresponding historical month."

The CFM module also consolidates forecasted calculations and manual inputs from the feeder modules to calculate deferred income taxes and income tax expense for presentation in the financial statements.

B. FLOWCHART

See MFR F-05 Attachment 07.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

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C. INTEGRATED MODULES

1. Electric Sales & Revenue (ES&R) Module

• Historical Information

On a monthly basis, historical information on electric and other revenues is updated into the ES&R via an interface from SAP. Some items that are not captured in the SAP data load are manually input into the ES&R.

• Forecasted Information

ES&R forecasts electric revenues for each customer class. Electric sales/loads (MWH) as well as production and fuel expense (in dollars) are fed from the production costing model (P-MArea) and used for calculations in the revenue module.
Electric sales and load forecast files are obtained from the Resource Assessment and Planning Department (RAP) and input into the ES&R module.
The ES&R module is also updated with RAP's electric production cost forecast that includes MWH produced, wholesale sales and purchases and fuel expense.
Retail Base and Wholesale Base Revenue Forecasts are provided by the Rates and Tariff Department and input into the ES&R module for each customer class.

The ES&R module uses the input data to calculate:

- MWH sales, electric production and fuel expense for use in calculations of base revenues and clause revenues.
- Rates by customer class.
- Fuel clause projections based on jurisdictional factors.
- Billed and unbilled revenues.
- Over/under recovery for all cost recovery clauses.

2. O&M Calculation Module

• Historical Information

On a monthly basis, historical information on operating and maintenance expenses is updated into the O&M module via an interface from SAP. Some items that are not captured in the SAP data load are manually input into the O&M module.

• Forecasted Information

O&M forecast data is obtained from Corporate Budgets via SAP and is input into the O&M module at a summary level.
This data is then output to the CFM for preparation of forecasted financial statements.

Supporting Schedules: | Recap Schedules:

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_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___
Witness: Robert E. Barrett, Jr., Renae B. Deaton, Joseph A. Ender, Kim Ousdahl, Dr. Rosemary Morley

Line No. (1)

3. Construction and Plant Accounting Module (CPA)

• Historical Information

On a monthly basis, historical data for property, plant and equipment is updated in the CPA module via an interface from the PowerPlan (PP). The Construction Work in Process (CWIP) is also updated on a monthly basis via an interface with PP.

• Forecasted Information

Capital expenditures forecast data is obtained from SAP and is interfaced into the CPA module. Forecasted retirements, depreciation rates, and tax depreciation on vintage assets are manually input into the CPA module.

The CPA module uses the input data to calculate plant activity, depreciation, deferred taxes and tax depreciation on asset additions. These calculations are then consolidated in the CFM module for use in generating financial statements.

4. Finance Module -- Long-term Financing

The Finance Module forecasts long-term financing activity for all outstanding debt and new debt instruments added to the model. Data is manually input into the module on an individual debt issue basis.

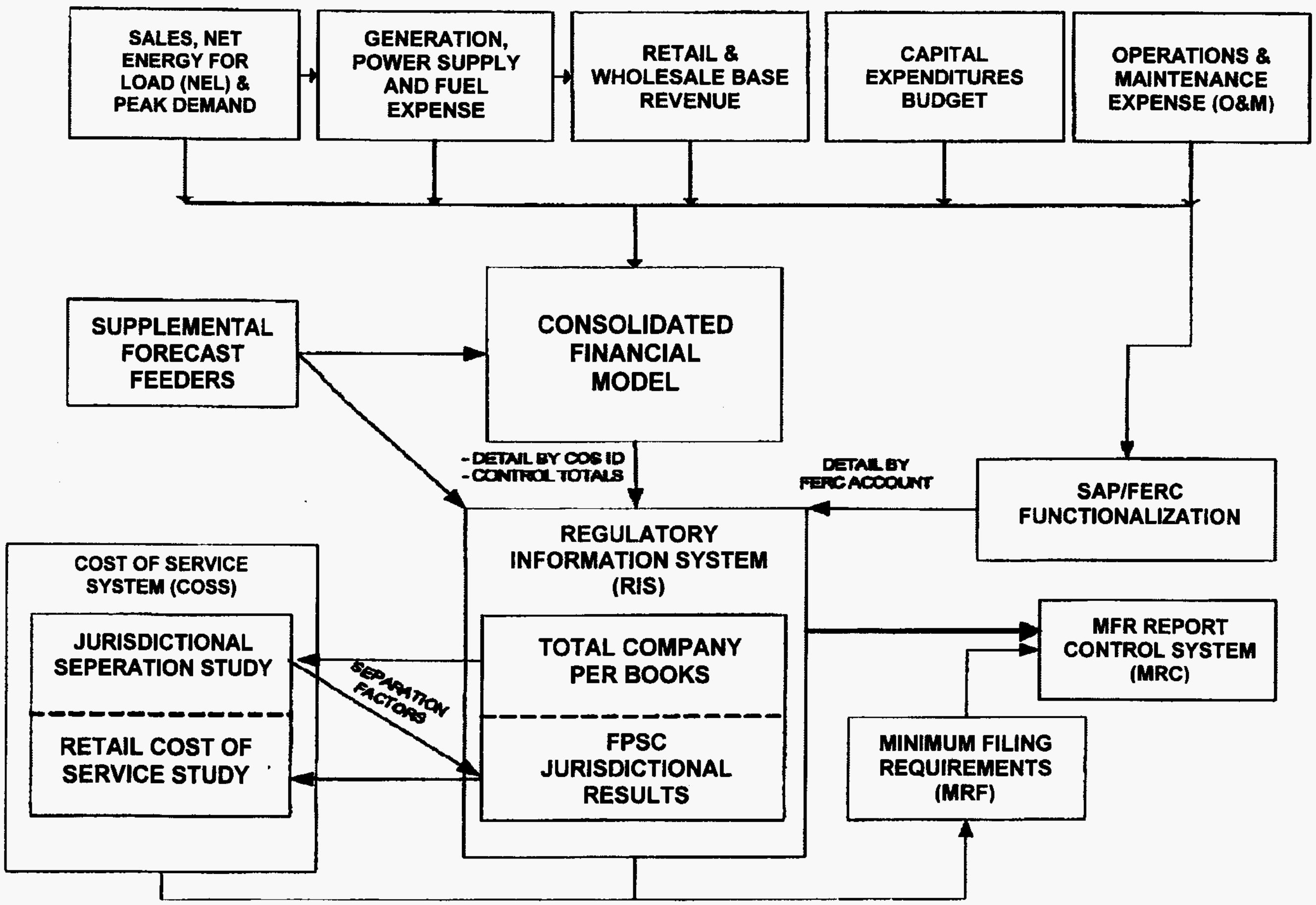
The module generates details of each issue's transactions for all items that apply to the income statement, cash flow statement, and balance sheet (issuances, retirements, premium, discounts, interest, amortization, etc.).

5. User Input Module - Other

The FP model also allows the input of forecast assumptions and actual values for items that are budgeted and calculated outside of the system that are not captured by the modules listed above. These include items such as property taxes, commercial paper rates, miscellaneous revenues, etc.

Supporting Schedules: Recap Schedules:

FLORIDA POWER & LIGHT COMPANY
FORECASTING PROCESS OVERVIEW



LOAD FORECASTING METHODOLOGY

The Load Forecasting section of the Finance department projects sales, customers, net energy for load and peaks.

Forecasts for 2012 thru 2013 are developed on a monthly basis for customers, net energy for load (NEL), sales and peaks. Customers and sales are developed by revenue class.

ASSUMPTIONS:

In developing the forecasts, assumptions were made about the most likely conditions for the economy, population, and weather. The forecasts for the economic variables were obtained from Global Insight. Population estimates are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed, in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. The weather data is gathered each month from four weather stations across our service territory.

Weather is the most important factor affecting the company's sales and peak demand. Weather variables are used in our forecasting models of sales, summer, and winter peak demand. There are three sets of weather variables developed and used in the forecasting models:

1. Cooling and heating degree-hours based on 72° F, winter heating degree-days based on 66° F, and heating degree-days based on 45° F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, are used to forecast Summer peaks.
3. The minimum temperature on the peak day, along with the build-up of heating degree-hours based on 66° F on the day prior to the peak are used to forecast Winter Peaks.

The cooling degree hours and heating degree days are used to capture the changes in the electric usage of weather sensitive appliances, such as air conditioners and electric heaters, that occur because of changing weather conditions. Heating degree days based on 45 degrees is used to capture heating load resulting from sustained periods of unusually cold weather not otherwise captured by heating degree days. The procedure for calculating cooling degree hours and heating degree days is as follows:

First a composite system-wide temperature is developed using hourly temperatures from the four weather stations (Miami, Fort Myers, Daytona Beach, West Palm Beach) in our service territory. The hourly temperatures from the four stations are weighted by the sales in that region to produce a system temperature.

Heating degree days are calculated by subtracting the actual average daily composite temperature from a base temperature of 66 ° (the negative values are ignored). The heating degree days are then summed for the given month to obtain a monthly value.

Cooling degree hours are calculated by subtracting a base temperature of 72° from the actual hourly composite temperature (the negative values are ignored). The cooling degree hours are then summed together for the day and divided by 24 to obtain daily cooling degree hours, which are then summed for the given month to obtain a monthly value.

CUSTOMER FORECAST:

The monthly customer forecast is developed by revenue class. Econometric models are developed for total, residential, commercial, industrial, and street & highway classes. For other public authority, railroads & railways, and resale, the forecast is based on customer specific information. The forecasts for all the revenue classes are summed and then the difference from the total customer model and the sum of the revenue class models are applied to the residential customer class.

Total Customer Forecast:

Total customers are projected using a regression model with an intercept term and Florida's population. In addition, the model has an autoregressive term lagged one month and a seasonal autoregressive term to correct for correlation in the residuals. The growth in Florida's population is a key indicator in projecting FPL's total customers. The model is as follows:

DEPENDENT VARIABLE: Total Customers

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-295894.256	-0.830
Florida Population	0.257	13.177
AR (1)	0.963	56.532
SAR (1)	0.820	27.747
Adjusted R-Square =	1.000	
Durbin-Watson =	1.718	

Residential Customer Forecast:

Residential customers are projected using a regression model with an intercept term and Florida's population. In addition, the model has an autoregressive term lagged one month and a seasonal autoregressive term to correct for correlation in the residuals. The growth in Florida's population is a key indicator in projecting FPL's residential customers. The model is as follows:

DEPENDENT VARIABLE: Residential Customers

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-251196.015	-0.757
Florida Population	0.227	12.591
AR (1)	0.959	54.110
SAR (1)	0.840	30.970
Adjusted R-Square =	1.000	
Durbin-Watson =	1.778	

Commercial Customer Forecast:

Commercial customers are projected using an econometric model with an intercept term, Florida Non-Agricultural employment, and an autoregressive term lagged one month as independent variables. The model is as follows:

DEPENDENT VARIABLE: Commercial Customers

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-775858.704	-0.525
Florida Non-Agricultural Employment	8.806	4.867
AR (1)	1.001	1427.136
Adjusted R-Square =	1.000	
Durbin-Watson =	1.647	

Industrial Customer Forecast:

Industrial customers can be segregated into two distinct groups; small customers including temporary construction accounts, and large and medium, more traditional industrial customers. Industrial customers are therefore projected using separate methods for each group. The small industrial customer model includes an intercept term, Florida housing starts lagged one month, Florida non-agricultural employment lagged one month, an autoregressive term lagged one month and a moving average term. Large and medium industrial customers are forecast by trending the historical series using an exponential smoothing model. The model for small industrial customers is as follows:

DEPENDENT VARIABLE: Small Industrial Customers

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-40238.525	-0.684
Florida Housing Starts (Lagged one month)	4.386	1.802
Florida Non-Agricultural Employment (Lagged one month)	4.488	3.807
AR (1)	0.997	115.769
MA (1)	0.540	8.879
Adjusted R-Square =	0.996	
Durbin-Watson =	2.031	

Street & Highway Customers:

Street & highway customers are projected using an econometric model with an intercept term and a one month lag of street & highway customers. The model is as follows:

DEPENDENT VARIABLE: Street & Highway Customers

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	10.263	1.718
Street & Highway Customers (Lagged one month)	0.999	480.898
Adjusted R-Square =	0.999	
Durbin-H Statistic =	2.144	

Other Public Authority:

This revenue class consists of one government account and sports fields. Sports fields, which is a closed rate schedule, account for the vast majority of customers in this revenue class. As a result, the number of customers in this revenue class is expected to decline gradually due to customer attrition.

Railroads & Railways:
This revenue class consists of Miami-Dade County's metro-rail stations. The number of customers is based on the planned addition of new stations.

Resale:

This class consists of wholesale customers that provide electricity to ultimate consumers. At the present time FPL has five such customers: City Electric, Inc. of Key West, Florida Keys Electric Cooperative, Metro-Dade County, Lee County Electric Cooperative, and the City of Wauchula.

ENERGY SALES FORECAST:

An econometric model is developed to produce a NEL per customer forecast. The key inputs to the model are: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, winter heating degree days, heating degree days based on 45 degrees, the ratio of inactive customers to total customers (the inactive ratio), CPI for energy, a term for weather sensitive mandated energy efficiency, and an intercept term. In addition, the model also includes dummy variables for February, April, June, September, November, March 2003, May 2004, and November 2005. The model below is based on NEL per customer, therefore the output is multiplied by total customers to derive FPL's net energy for load forecast.

DEPENDENT VARIABLE: Net Energy for Load per Customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	1.548	17.526
Heating Degree Days based on 45 degrees	0.017	5.219
Cooling Degree Hours	0.003	74.874
Winter Heating Degree Days	0.001	15.191
Inactive Ratio	-2.698	-3.721
Weather Sens Mandated Energy Efficiency	-1.796	-6.042
Weighted Real Per Capita Income	0.022	4.339
Dummy March 2003	0.098	4.317
Dummy February	-0.147	-19.374
Dummy April	-0.036	-4.723
Dummy June	-0.055	-7.197
Dummy September	-0.052	-7.088
Dummy May 2004	0.111	4.933
Dummy November	-0.057	-6.576
Dummy November 2005	0.106	4.503
CPI Energy	-0.0004	-2.544
AR (1)	0.323	3.453

Adjusted R-Square = 0.994
Durbin-Watson = 2.062

Once the NEL forecast is obtained using the above-mentioned model, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts discussed below for the residential and commercial classes are then adjusted proportionally to match the NEL from the NEL model.

To project sales by revenue class, models for the residential, commercial, and industrial classes are developed. The sum of all the classes will result in total sales, which is adjusted for the total sales derived from the NEL model. The models are developed to obtain a reasonable monthly share of each revenue class.

Residential Sales:

Sales for this revenue class are projected using an econometric model. Residential sales are a function of heating and cooling degree hours, the real retail price of gasoline lagged one month, Florida real per capita income weighted by the percent of the population employed, and an intercept term. The model below is based on residential sales per customer, therefore the output is multiplied by total residential customers to derive FPL's residential sales forecast.

DEPENDENT VARIABLE: Residential sales per customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	0.408	5.131
Cooling Degree Hours	0.001	17.747
Heating Degree Hours	0.001	12.869
Weighted Real Per Capita Income	0.029	5.302
Heating Degree Hours (Lagged 1 month)	0.001	4.831
Cooling Degree Hours (Lagged 1 month)	0.001	11.106
Real Retail Price of Gasoline (Lagged 1 month)	-0.106	-5.597

Adjusted R-Square = 0.925
Durbin-Watson = 1.812

Commercial Sales:

Sales for this class are forecasted using an econometric model. Commercial sales are a function of cooling and heating degree hours, Florida real per capita income weighted by the percent of the population employed, the inactive ratio, and an autoregressive term. The model also includes an intercept and two dummy variables for December and for January 2007. The model below is based on commercial sales per customer, therefore the output is multiplied by total commercial customers to derive FPL's commercial sales forecast.

DEPENDENT VARIABLE: Commercial Sales per customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	5.955	13.224
Cooling Degree Hours	0.003	9.740
Heating Degree Hours	0.001	2.968
Weighted Real Per Capita Income	0.078	3.140
Cooling Degree Hours (Lagged 1 month)	0.003	9.636
Inactive ratio	-10.859	-3.777
Dummy December	0.369	5.571
Dummy January 2007	0.943	4.529
AR (1)	0.154	1.726

Adjusted R-Square = 0.896
Durbin-Watson = 1.923

Industrial Sales:

Sales for the industrial class are forecast using separate econometric models for each group; small customers, medium customers, and large customers. The key inputs to the small industrial sales model are heating and cooling degree hours, Florida disposable income, and an autoregressive term. The model also includes an intercept term and a dummy variable for February 2009. Key inputs into the medium industrial sales model are cooling degree hours, Florida disposable income, a seasonal autoregressive term, a moving average term, an intercept term, and a dummy variable for February 2006. Key inputs into the large industrial customer sales model are Florida real per capita income, the price of electricity, the consumer price index, an intercept term, and a dummy variable for October 2004. The small industrial sales model below is based on industrial sales per customer therefore the output from this model is multiplied by the number of small industrial customers to derive the sales forecast for this group. These sales are summed with the sales forecasts from the medium and large industrial customers to derive FPL's industrial sales forecast.

DEPENDENT VARIABLE: Small Industrial Sales per customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	0.1265	0.7344
Cooling Degree Hours	0.0006	11.4118
Heating Degree Hours	0.0003	4.5610
Dummy February 2009	-0.0581	-2.2362
Disposable Income	0.000001	2.0001
AR (1)	0.7607	11.6155

Adjusted R-Square = 0.856
Durbin-Watson = 2.161

DEPENDENT VARIABLE: Medium Industrial Sales

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-115623.7061	-0.7368
Disposable Income	0.0605	2.9266
Cooling Degree Hours	13.2533	2.9917
Dummy February 2006	-5508.4916	-4.3175
SAR (1)	0.9785	30.7745
MA (1)	0.2649	3.0309

Adjusted R-Square = 0.859
Durbin-Watson = 1.790

DEPENDENT VARIABLE: <u>Large Industrial Sales</u>

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	321093.629	7.207
Per Capita Income	11039.085	6.199
Real Price of Electricity (24 month moving average)	-1123781.532	-1.441
Consumer Price Index	-1973.630	-10.906
Dummy for October 2004	-122937.742	-7.043

Adjusted R-Square = 0.679
Durbin-Watson = 1.914

Street & Highway Sales:

Street & highway sales are projected using a trended use per customer, which is multiplied by the forecasted number of customers.

Other Public Authority Sales:

This revenue class is a closed class with no new customers being added. This class consists of sports fields and a government account. The forecast for this class is based on historical usage characteristics.

Railroads & Railways Sales:

The projections for sales in this class are based on historical average use per customer times the number of customers in the class. The number of customers is based on the planned addition of new stations.

Resale Sales:

Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently there are five customers in this class: the Florida Keys Electric Cooperative, City Electric, Inc. of Key West, Metro-Dade County, Lee County Electric Cooperative, and the City of Wauchula. Sales to the Florida Keys are based on the customers forecast of their own demand and historical load factors. Forecasted sales to City Electric, Inc. of Key West are based on assumptions regarding their contract demand and expected load factor. Metro-Dade County sells 60 MW to Florida Progress. Line losses are billed to Metro-Dade under a wholesale contract. Lee County Electric Cooperative provides a forecast of their sales by delivery point which is used to derive their sales forecast. Sales to the City of Wauchula are based on a regression model.

Total Sales:

The forecasts for all revenue classes are summed and the residential and commercial classes are adjusted proportionately to match the total sales forecast obtained from the NEL model.

SYSTEM PEAK FORECASTS

The forecasting methodology for the summer and winter system peaks are discussed below.

System Summer Peak

The summer peak forecast is developed using an econometric model. The variables included in the model are the price of electricity, Florida real per capita income weighted by the percent of the population employed, cooling degree hours during the day prior to the peak, maximum temperature on the day of the peak, and a term for mandated energy efficiency. The model also contains an intercept term and dummy variables for 1982, 1989, and 1990. The model below is based on summer peak per customer, therefore the output is multiplied by total customers to derive FPL's system summer peak.

DEPENDENT VARIABLE: Summer Peak Per Customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	-1.385	-1.462
Weighted Real Per Capita Income	0.068	9.030
Real Price of Electricity (Lagged 1 month)	-9.331	-4.861
Maximum Peak Day Temperature	0.049	4.662
Prior Day Cooling Degree Hours	0.003	4.583
Mandated Energy Efficiency	-0.441	-2.054
Dummy 1982	0.222	2.476
Dummy 1990	-0.267	-3.100
Dummy 1989	-0.212	-2.469
Adjusted R-Square =	0.926	
Durbin-Watson =	2.045	

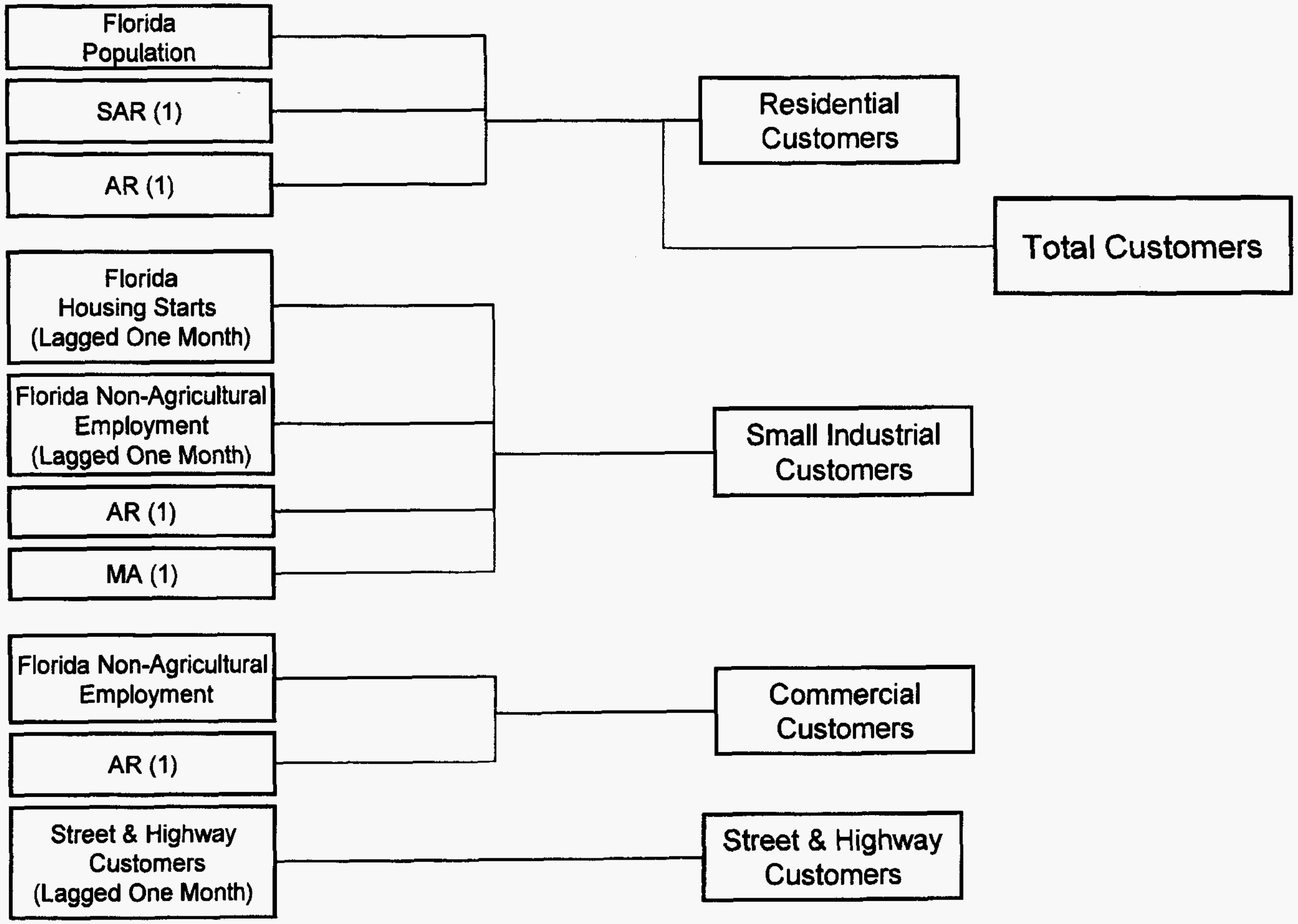
System Winter Peak

Like the system summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the minimum temperature on the day of the peak and heating degree hours for the day before and morning of the winter peak day. In addition there is a dummy variable for peaks occurring during the weekend. The model also contains an intercept term. Results of the model are adjusted for mandated energy efficiency. The model below is based on winter peak per customer, therefore the output is multiplied by total customers to derive FPL's system winter peak.

DEPENDENT VARIABLE: Winter Peak Per Customer

INDEPENDENT VARIABLE:	COEFFICIENTS	T RATIO
Intercept	6.800	11.828
Minimum Peak Day Temperature	-0.072	-5.948
Prior Day HDH Square	0.000001	3.074
Dummy Weekend Winter Peak	-0.550	-3.851
AR (1)	0.394	2.002
Adjusted R-Square =	0.802	
Durbin-Watson =	1.904	

CUSTOMER MODELS



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MFR NO. F-05
ATTACHMENT 3 OF 9
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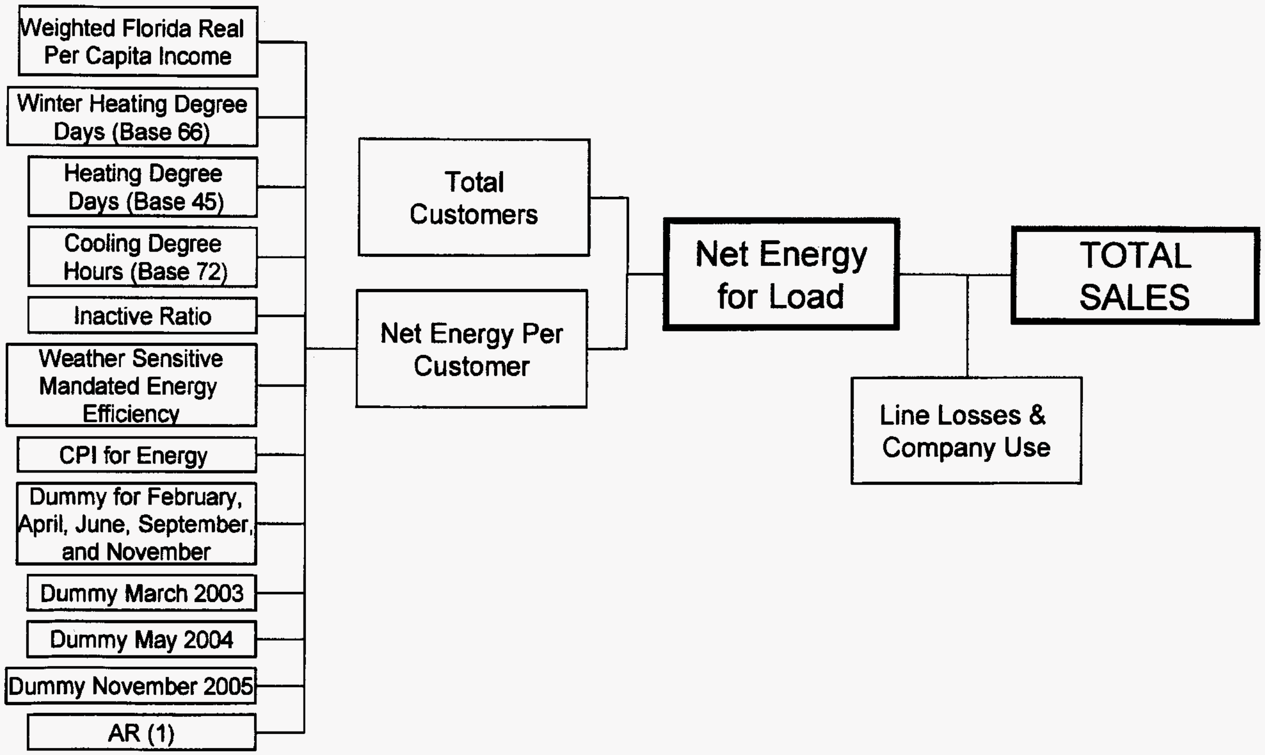
Florida Power & Light Company
Short-Term Net Energy for Load Model



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AND SUBSIDIARIES
DOCKET NO. 120015-EI
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ATTACHMENT 4 OF 9
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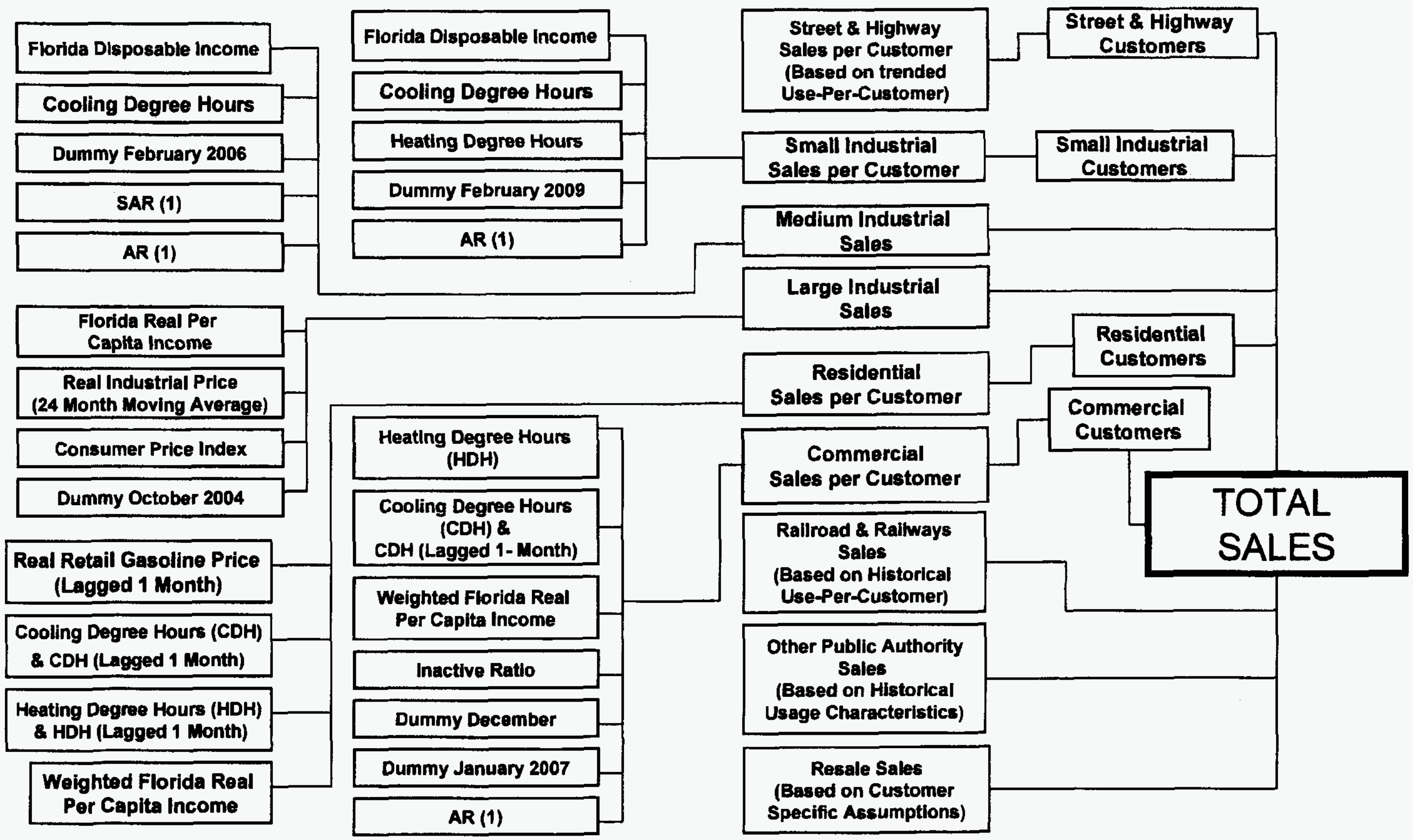
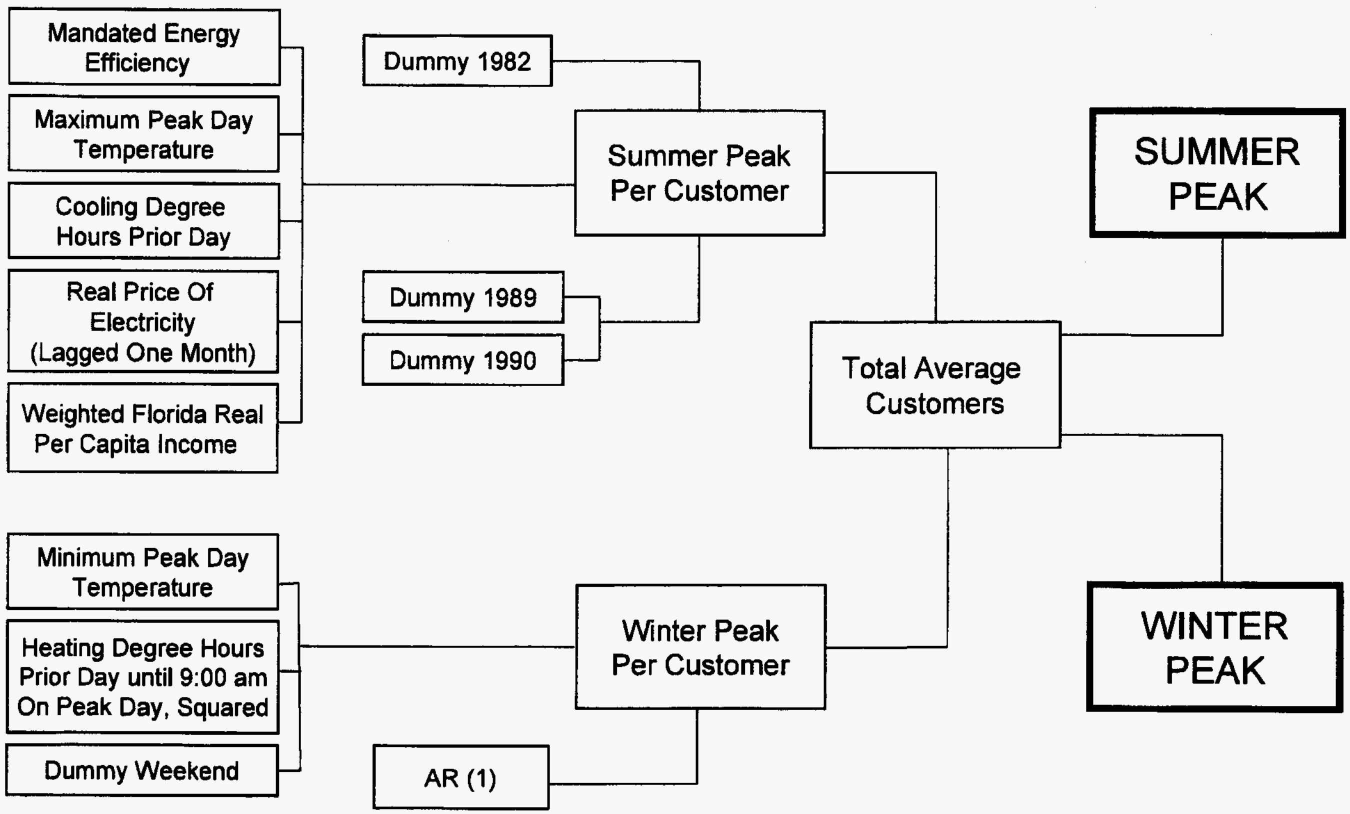
Florida Power & Light Company
Total Short-Term Sales By Customer Class



Florida Power & Light Company
Modeling the Summer & Winter Peaks



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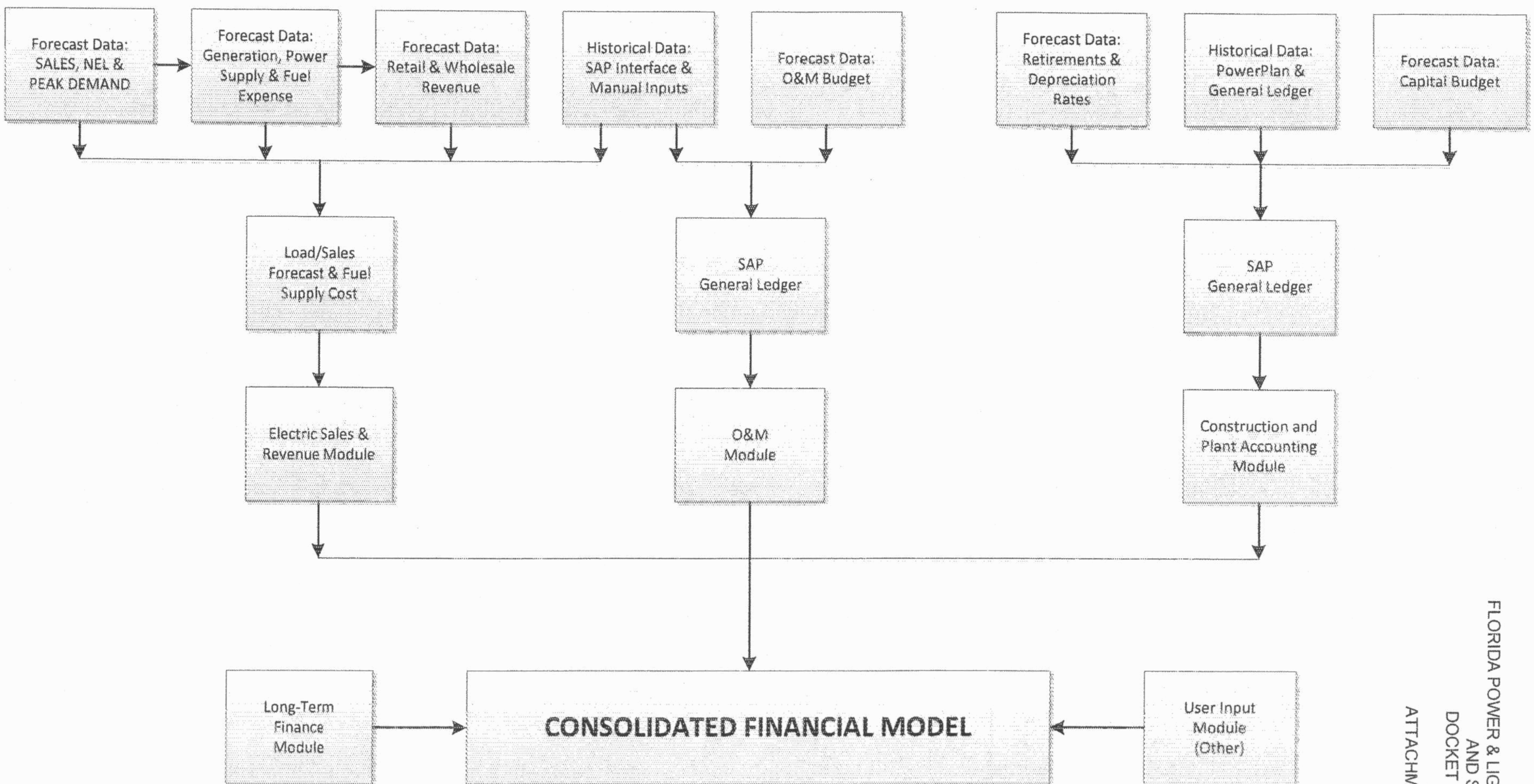
FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED FINANCIAL MODEL (CFM)



Florida Power & Light Company

2012

Planning and Budgeting Process

Guideline

Contents

(1) see Excel file: FPL_2012_PlngProc_Sec3_Apndx.xls)

2012 Planning and Budgeting Process Calendar

Item	Date	Day	Action / Deliverable / Event	Comment / Reference
1	9-Apr	Fri	Planning Assumptions and Guidelines issued.	Provided by Corporate Budgets.
2	11-Apr	Mon	Units begin to develop 2012-2014 O&M budgets and 2012-2016 Capital Budgets.	Guidance given by Corp Budgets.
3	27-May	Fri	Units submit Budget Presentation to Corp Budgets in advance of Armando Olivera (AJO) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
4	9-Jun	Thur	**Armando Olivera Budget Review Meeting** Business units present to AJO & Budget Review Committee.	Applies to certain business units. See Section 1, Page 8.
5	27-Jun	Mon	Units submit Budget Presentations to Corp Budgets in advance of Jim Robo (JR) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
6	1-Jul	Fri	Those business units with budget activities related to the Affiliate Management Fee, Affiliate Service Fees, or Affiliate Direct Charges, load all budget details for those budget activities, for 2012-2014.	Applies to all business units. See Section 2, Page 3.
7	8-Jul	Fri	**Benchmark:** business unit detail budgets for all required periods should be substantially complete in SEM SAP.	No deliverable at this time. See Item 11.
8	11-Jul	Mon	AJO review of the current status of 2012 Plan with Corp Budgets prior to the 7/14 JR meeting.	No unit participation required at this time.
9	13-Jul	Wed	All business units load all budget details, for all expense types, for the remaining months of 2011.	Applies to all business units. See Section 2, Page 3.
10	14-Jul	Thur	**Jim Robo Budget Review Meeting** Corp Budgets presents to JR, AJO & Budget Review Committee.	No unit participation required at this time. See Section 1, Page 8.
11	22-Jul	Fri	All business units load all **final** budget details, for all expense types and work force, for 2012-2014. All business units load all **final** budget details, for all capital expense types, for 2015-2016. All business units submit all **final** required supporting schedules, for 2012-2014.	Applies to all business units. See Section 2, Pages 2-3.
12	3-Aug	Wed	Units submit **final** Budget Presentations to Corp Budgets in advance of Lew Hay (LH) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
13	17-Aug	Wed	**Lew Hay Budget Review Meeting** FPL Final Budget Review Mtg with LH, JR, AJO & Budget Review Committee.	No unit participation required at this time. See Section 1, Page 9.
14	22-Aug	Mon	If necessary, all business units update all deliverables submitted on July 22 (Item 11 above)	Applies to all business units. See Section 2, Pages 2-3.
15	31-Aug	Wed	If necessary, all business units update Budget Presentations submitted on August 3 (Item 12 above)	Applies to all business units. See Section 1, Page 9
16	30-Nov	Wed	All business units submit updated Performance Measure sheets	Applies to all business units. See Section 2, Page 3.

Overview of 2012 Planning and Budgeting Process

Section 1 of the 2012 Planning Process Guideline provides instructions for preparing the business unit budget presentations.

Section 2 of the Guideline provides instructions for preparing the supporting data schedules and the on-line detail budgets.

Section 3 of the Guideline is an appendix that includes the templates and data schedules referenced in Sections 1 and 2, as well as other reference material.

Review the entire Guideline carefully as there have been numerous modifications from last year. Throughout Section 2 of the Guideline there are symbols in the right hand margin indicating "New" requirements and providing a "Reminder" for important existing requirements.

This year's planning and budgeting cycle is the last time that we will use SEM SAP to load detail budgets. Once funding levels are approved and final detail budgets are loaded the detail budgets will be converted to IP SAM.

To facilitate the conversion, there are two significant changes we are making to how we load detail budgets this year. For this planning cycle, monthly payroll will be budgeted based on work days, not pay period closings. Also, business units will not budget for the March payout of incentives. Incentives will become a payroll overhead to be applied to all budgeted exempt payroll during conversion.

The conversion process will apply the appropriate payroll overheads to all budgeted payroll; therefore, business units should not budget for any payroll overheads during this planning cycle.

The results of this year's planning and budgeting cycle will serve as an input for many of the schedules that will be prepared for the upcoming rate case. In an effort to ensure the quality and accuracy of the budgets underlying the rate case, a corporate team will review each business unit's detail budget to evaluate important budget design elements such as the correct use of budgeted expense types and the relationship of payroll cash flows to work force budgets. Towards the end of the planning cycle, individual review sessions will be scheduled with the major line and staff business units, while the smaller units will be handled on an exception basis.

For this year's planning cycle, <u>two deliverables normally required have been eliminated</u>: the R-Schedule and the Five Year Capital Forecast. The information previously provided in the R-Schedule will be obtained from the various elements of the Budget Presentation. The requirements of the Five Year Capital Forecast will be satisfied by extending the capital detail budgets by two years. The elimination of these deliverables will reduce both preparation time and the need to reconcile related schedules. However, to ensure that the information previously provided by these documents is still available to Corporate Budgets, it is imperative that all required elements of Business Plan be present and the instructions for developing capital budgets be followed carefully.

Florida Power & Light Company

2012 Planning and Budgeting Process Guideline

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Section 1

Developing Budget Presentations

Budget Presentation Development

This section provides the requirements for the development of the Budget Presentation deliverable.

All business units are required to prepare a Budget Presentation deliverable for submittal to Corporate Budgets (see Calendar Items 3, 5, and 12).

The Budget Presentation must contain the following sections:

1. Objectives and Goals

List the business unit's objectives and goals. Objectives and goals should state ***what*** the business unit intends to accomplish and should support both corporate and business unit priorities.

2. Key Initiatives

List the business unit's key initiatives. Key initiatives should state ***how*** the business unit intends to accomplish its objectives and goals.

3. Assumptions

List the assumptions on which the business unit's plans and budgets are based. Assumptions should include any internal or external influences such as work force reductions/increases, changing operational requirements, economic factors, and regulatory, political and social developments.

4. Benchmarking and Performance Indicators

Identify relevant business unit performance measures, and compare the unit's performance to the industry's performance, or another relevant benchmark, using graphs or tables, as appropriate.

Performance measures should be both financial (cost) and operational (quality). Include at least five years of performance if the data is available. Identify the industry average, as well as the top quartile and the top decile entry points where available.

If your unit's performance is below the top quartile entry point on a particular indicator, use Section 2 - Key Initiatives to identify efforts to close the gap.

5. Cost and Employment Summaries

Prepare separate schedules identifying your business unit's Base O&M, Below the Line and Total Capital funding requirements, FPL Employment levels, and Gross Payroll. Units may develop their own forms, patterned after the examples, or use the blank templates provided in the appendix.

For each cost schedule, list the major projects and activities to be under taken by your unit for the years identified. ***Select a level of detail appropriate for a thorough senior executive review.*** For each project and activity, identify the performance indicators impacted and be prepared to discuss the risk if funding is not approved.

Base O&M
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Project / Activity 4								
Project / Activity 5								
Project / Activity 6								
Project / Activity 7								
Project / Activity 8								
Project / Activity 9								
Project / Activity 10								
Total Base O&M								

Below the Line
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Project / Activity 4								
Project / Activity 5								
Project / Activity 6								
Project / Activity 7								
Project / Activity 8								
Project / Activity 9								
Project / Activity 10								
Total Below the Line O&M								

The Total Capital schedule should be stratified into base capital and clause recoverable capital, with sub-totals for each, per the example.

Total Capital
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Base Capital								
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Total Base Capital								
Conservation Clause								
Project / Activity 4								
Environmental Clasue								
Project / Activity 5								
Total Clause Capital								
Total Capital								

On the FPL Employee / Gross Payroll schedule, count part time positions as 1.0 each. Do not use the detail budgeting and reporting convention of counting part timers as 0.5 each. Also, include the gross FPL utility payroll for your business unit, regardless of where it will be charged (corresponds to payroll EACs 801 through 808 and 820 through 822), but do not include payroll charged to you from other units or non-utility entities.

FPL Employees / Gross Payroll
Business Unit: ____________________

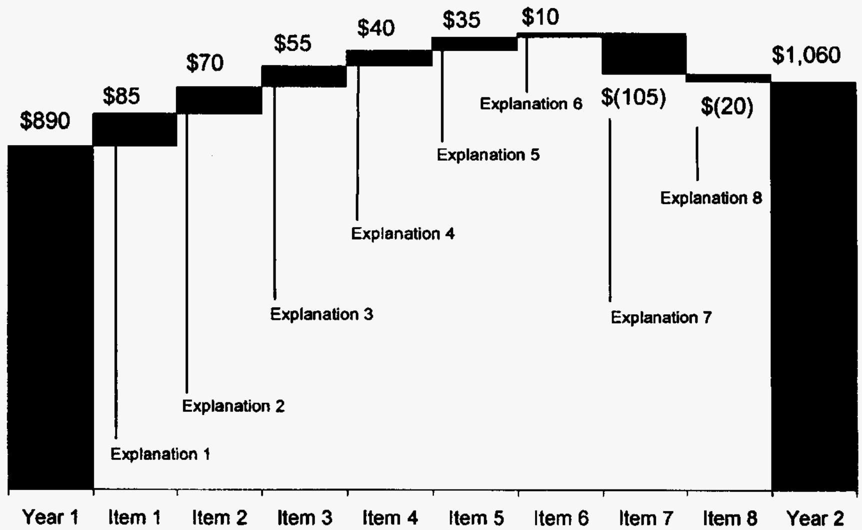
Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Approved	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast
Full Time (excluding Temporaries)								
FPL Exempt								
FPL Non-Exempt								
FPL Bargaining Unit								
Total FPL Full Time Employees								
Part Time (count each as 1.0)								
FPL Exempt								
FPL Non-Exempt								
FPL Bargaining Unit								
Total FPL Part Time Employees								
Total FPL Employees (excluding Temporaries)								
Gross Payroll								
(Includes Regular, Overtime, Unit Recognition Progs,								
(Lump Sum, Other Earnings, and LTI / Defered Comp)								

6. Operating Expense Walks

Prepare separate waterfall charts for Base O&M and Below the Line expenses for each of the following comparisons:

- 2011 Current Approved Budget to 2011 Forecast
- 2011 Forecast to 2012 Funds Request
- 2012 Funds Request to 2013 Funds Request
- 2013 Funds Request to 2014 Funds Request

Include a brief explanation for each step-up and step-down on the chart.



7. FPL Employee Walk

Prepare a schedule for each of the following FPL employee comparisons:

- 2011 Current Approved Budget to 2011 Forecast
- 2011 Forecast to 2012 Funds Request
- 2012 Funds Request to 2013 Funds Request
- 2013 Funds Request to 2014 Funds Request

8. Charges to Affiliates

Prepare separate schedules identifying your business unit's costs that will be allocated, in part or in whole, to affiliated companies. Units may develop their own forms, patterned after the examples, or use the blank templates provided in the appendix.

List the major projects and activities to be under taken by your unit for each of the allocation methods listed below. ***Select a level of detail appropriate for a thorough senior executive review.***

- Affiliate Management Fee Pools (Expense Type 1 - Base O&M)
- Service Fees (Expense Type 1 - Base O&M)
- Direct Charges (Expense Type G - Direct Charges)

In the case of Affiliate Management Fee Pools, indicate the driver of any cost increases. In the case of Service Fees and Direct Charges, indicate the entity being charged. Report all costs as they are to be incurred by the business unit. ***Do not add loaders and do not apply any allocation rates to the costs reported.***

Affiliate Management Fee Pools
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Drivers
Project / Activity 1							
Project / Activity 2							
Project / Activity 3							
Project / Activity 4							
Project / Activity 5							
Total AMF Pools							

Service Fees and Direct Charges
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Charged To (check box)		
							NextEra Energy, Inc. (Corporate)	NextEra Energy Resources	Other (FiberNet, FPLES, etc)
Service Fees									
Project / Activity 1									
Project / Activity 2									
Total Service Fees									
Direct Charges									
Project / Activity 3									
Project / Activity 4									
Total Direct Charges									

9. Transfer of Resources Between Business Units

As a matter of company practice, a business unit is not permitted to assign its existing budget resources, and or budget responsibilities, to another business unit, unless directed to do so by executive management.

If a business unit has been directed by executive management to transfer resources to another unit, then the affected units should reflect the transfer in their respective budget presentations, identifying the transfer as a separate line item in steps 3, 5, 6 and 7 above. Neither unit should net the transfer with other processes or activities such that the reduction and addition and cannot be reconciled by Corporate Budgets during its review of the units' budget presentations.

If a business unit believes there is a business basis for a transfer of resources, the business unit may propose such a transfer during the annual planning and budgeting process. However, the business unit may not unilaterally reflect the transfer in its budget presentation. The business unit must coordinate the transfer through the Corporate Budgets Director Guy Casaceli to obtain Corporate Budgets concurrence and to ensure the receiving business unit is notified of the proposal. Business unit resource transfer proposals will be evaluated on a case by case basis. Both units may be instructed to reflect the transfer in their respective budget presentations as described in the paragraph above, or the proposal may deferred for executive consideration at the next scheduled budget review meeting.

Budget Review Committee

The Budget Review Committee for the 2012 planning cycle will include the following individuals:

- FPL President & Chief Executive Officer – Armando Olivera
- FPL Group Senior Vice President Finance and Chief Financial Officer – Armando Pimentel
- FPL Vice President Finance – Bob Barrett
- FPL Group Senior Vice President Strategy, Policy and Business Process Improvement – Chris Bennett
- FPL Vice President Controller and Chief Accounting Officer – Kim Ousdahl
- FPL Director Corporate Budgets – Guy Casaceli

Additional executives may be added to the Committee during the planning cycle.

Presentations and Budget Review Meeting Support

Business unit participation in the scheduled budget review meetings is as follows.

First Budget Review Meeting – June 9

The business units listed below are required to make a presentation of resource requirements to the Budget Review Committee on **Thursday, June 9** (see Calendar Item 4).

Specific times for each business unit presentation have been communicated separately. Presenters only need to be in attendance at the meeting for their individual presentations. Business unit controllers are recommended to be on standby in the ante room of the large executive conference room.

In preparation for the first Budget Review Meeting, all business units, including those not presenting, must submit their Budget Presentation materials to Corporate Budgets by **Friday, May 27** (see Page i, Calendar Item 3).

- Nuclear
- Power Generation
- Distribution
- Transmission
- Customer Service
- Engineering & Construction / Corporate Services
- Project Development
- Information Management
- Human Resources
- General Counsel
- Marketing & Communications
- Strategy and Business Policy

The submittals from those business units not presenting at the meeting will be made available to the Committee by Corporate Budgets.

Second Budget Review Meeting – July 14

At this time there is no expectation of business unit participation in the Budget Review Meeting on **Thursday, July 14** (see Calendar Item 10).

In preparation for the second Budget Review Meeting, all business units must submit updated Budget Presentations by **Monday, June 27** (see Calendar Item 5).

Final Budget Review Meeting – August 17

At this time there is no expectation of business unit participation in the Budget Review Meeting on **Wednesday, August 17** (see Calendar Item 13).

In preparation for the third Budget Review Meeting, all business units must submit updated Budget Presentations by **Wednesday, August 3** (see Calendar Item 12).

Final Version of Budget Presentation

Each business unit is required to provide a final version of its Budget Presentation to Corporate Budgets by **Wednesday, August 31** (see Calendar Item 15). Include the following sections:

1. Objectives and goals
2. Key initiatives
3. Assumptions
4. Benchmarking and Performance Indicators
5. Cost and Employment Summaries
6. Operating Expense Walks
7. FPL Employee Walk
8. Charges to Affiliates

Final Budget Presentation versions must tie to the resource levels approved at the Final Budget Review Meeting on August 17.

The final Budget Presentation version will document the results of the planning process and will be produced if needed in response to rate case discovery requests.

Florida Power & Light Company
2012 Planning and Budgeting Process
Guideline

****

Section 2

Completing
Supporting Data Schedules
and
Detail Budgets

Overview of Section 2 Instructions and Section 3 Appendix

Section 2 of the Guideline provides instructions for preparing the supporting data schedules and the on-line detail budgets.

Review the entire Guideline carefully as there have been numerous modifications from last year. Throughout Section 2 of the Guideline there are symbols in the right hand margin indicating "New" requirements and providing a "Reminder" for important existing requirements.

In addition to the on-line detail budget, there are required supporting schedules that must be prepared. The schedules are included in Section 3: Appendix of Supporting Schedules and References (file: FPL_2012_PlngProc_Sec3_Apndx.xls).

Each schedule in the appendix includes sample entries for illustrative purposes only. Remove all of the illustrative data before completing and submitting the schedules.

Summary of Requirements for Supporting Schedules and Detail Budgets

This section provides an overview of the requirements for the completion and submittal of supporting data schedules and on-line detail budgets. All final submittals must tie to the resource levels approved at the Final Budget Review Meeting on August 17.

All business units are required to provide the following Supporting Schedules to Corporate Budgets by **Friday, July 22** (see Calendar Item 11).

- **Schedule 1: Charges to Other Business Units**
  - Complete using an Excel spreadsheet available in the Appendix, Section 3
  - Identify annual charges to other business units for years 2012-2014
    - product or service provided
    - business unit receiving product or service
    - payroll and non-payroll amounts

- **Schedule 2: Charges To Affiliates**
  - Complete using Excel spreadsheets available in the Appendix, Section 3
  - Identify annual charges to affiliated companies for years 2012-2014
    - product or service provided
    - entity receiving product or service
    - payroll and non-payroll amounts
  - These schedules will be used by Corporate to prepare rate case MFRs and respond to discovery

- **Schedules 3: Charges From Affiliates**
  - Complete using Excel spreadsheets available in the Appendix, Section 3
  - Identify annual charges from affiliated companies for years 2012-2014
    - product or service provided
    - entity providing product or service
    - payroll and non-payroll amounts
  - These schedules will be used by Corporate to prepare rate case MFRs and respond to discovery

- **Explanation and Justification of Incremental Positions**
  - Complete using Excel spreadsheets available in the Appendix, Section 3
  - Explain and justify each annual incremental addition
    - Forecasted 2011 increases above authorized 2011 level
    - Forecasted 2012 increases above forecasted 2011 level
    - Forecasted 2013 increases above forecasted 2012 level
    - Forecasted 2014 increases above forecasted 2013 level
  - These schedules will be used by Human Resources to prepare rate case testimony and respond to discovery

All business units are required to provide the following Supporting Schedule to Corporate Budgets by **Wednesday, November 30** (see Calendar Item 16).

- **Performance Measure Worksheet**:
  - Completed using Excel spreadsheet per the sample in the Appendix, Section 3
  - Include the following
    - estimated performance for the current year 2011
    - proposed indicators and performance targets year 2012
    - projected indicators and performance for years 2013-2014
  - This schedule will be reviewed by senior management in preparation for final approval of indicators and targets for 2012

All business units are required to complete the following by the dates indicated (see Calendar Items 6, 9 and 11).

- **Detail Budgets**
  - **Monthly cash flows for remainder of the current year 2011 (July – Dec)**
    - Complete on-line in SEM SAP Business Unit Budget folders
    - **Due Wednesday, July 13**
      - Update all expense types listed in item (1) below
      - All business units load all final 2012-2014 budget details
      - Final details will be frozen and readied for conversion to IP SAP

  - **Monthly cash flows for years 2012 - 2014**
    - Complete on-line in SEM SAP Original Budget folders
    - **Due Friday, July 1**
      - Update all expense types in item (2) below.
      - Business units with budget activities related to the Affiliate Management Fee (AMF), Affiliate Service Fees, or Affiliate Direct Charges load all 2012-2014 budget details for those activities
      - Detail will be used to calculate credits from affiliates
    - **Due Friday, July 22**
      - Update all expense types in item (1) below.
      - All business units load all final 2012-2014 budget details
      - Final details will be frozen and readied for conversion to IP SAP

  - **Monthly cash flows for years 2015 - 2016**
    - Complete on-line in SEM SAP Original Budget folders
    - **Due Friday, July 22**
      - Update all expense types in item (3) below.
      - All business units load all final 2015-2016 budget details
      - Final details will be frozen and readied for conversion to IP SAP

1. O&M Base; O&M clauses: Conservation, Environmental, Capacity and Fuel; Non-clause fuel; Below the Line; Revenue Enhancement Revenue and Expense; Re-Directed Expense; Inter-Company Expenditures; Capital Base; Capital clauses: Conservation and Environmental; Deferred Capital; and Work force
2. O&M Base and Inter-Company Expenditures (Expense Type G) only
3. Capital Base; Capital clauses: Conservation and Environmental; and Deferred Capital only.

R-Schedule

NEW

- The R-Schedule folder, previously available in SEM SAP, is no longer a deliverable of the annual planning process.
- The data elements previously provided by the R-Schedule will be gathered from the Budget Presentation deliverable and the detail budgets.
- Supporting Data Schedules, previously known as Supplemental R-Schedules, **continue to be required of all business units** (see below).

Supporting Data Schedules

NEW

General Requirements:

- There are four Supporting Data Schedules.
  - Schedule 1: Charges to Other Business Units (Expense Type 7)
  - Schedule 2: Charges to Affiliates (Expense Type G and Unit Service Agreements)
  - Schedule 3: Charges from Affiliates
  - Explanation and Justification of Incremental Positions

- Schedules 1, 2 and 3 must be completed for each of four years: 2011- 2014
  - Submit a total of 12 schedules
  - If nothing to report for a particular year/schedule, submit the schedule indicating "None"

NEW

- Explanation and Justification of Incremental Positions
  - Submit one schedule for each year

Completing the Supporting Data Schedules 1, 2 and 3

REMINDER

- Formats for each Supporting Data Schedule are included in the Appendix
  - Enter the name of the unit and the name of the preparer in the spaces provided
  - Enter all data in thousands of dollars.
  - Shaded cells will calculate automatically.
  - Check for mathematical integrity when inserting, deleting or moving rows, etc.
  - Ensure all illustrative data has been removed from each schedule being submitted.
  - Submit all completed schedules in a single work book.

  - Identify the business unit when naming the work book.

Schedule 1: Charges to Other Business Units

- Prepare a separate schedule for each year 2011 through 2014
- Expense Type 7 – Redirected Expenses
  - Expenditures incurred by your business unit, but reflected in another business unit's budget.
- Include the following:
  - product or service provided
  - business unit receiving product or service
  - payroll and non-payroll amounts
- The annual total for each Schedule 1 should tie to the Expense Type 7 annual total in the corresponding SEM/SAP Original Budget folder

Schedule 2: Charges to Affiliates

- Prepare a separate schedule for each year 2011 through 2014
- Expense Type G – Inter-Company Expenses
  - Expenditures to be direct-charged to each subsidiary through the FPL financial system
  - Include the following:
    - ◊ product or service provided
    - ◊ entity receiving the product or service
    - ◊ payroll and non-payroll amounts
  - Note: Next-Era typically accepts only payroll charges through FPL's financial system. However, certain recurring transactions, such as insurance premiums, customarily charged to Next-Era via Expense Type G should be budgeted on Schedule 2.
  - The annual Expense Type G total for each Schedule 2 should tie to the Expense Type G annual total in the corresponding SEM/SAP Original Budget folder
- Service Agreement Fees
  - This category applies only to Energy, Markets & Trading; Information Management, the Power Generation Division; and the Nuclear Division.
  - The value of services provided to affiliates, recovered dollar for dollar via the fee arrangement. Do not include the credit offsets from the affiliate, or the overheads recovered in Location 10.
  - Include the following detail:
    - ◊ product or service provided
    - ◊ entity receiving the product or service
    - ◊ payroll and non-payroll amounts
  - The annual Service Agreement Fee total for each Schedule 2 should tie to the debit side of the Service Fee detail budget in the corresponding SEM/SAP Original Budget folder. (In the detail

budget, service fees should be budgeted as Base O&M debits with offsetting credits, indicating full recovery of the expenditures.)

Schedule 3: Charges from Affiliates

- Prepare a separate schedule for each year 2011 through 2014
- Identify the fully loaded charges to be incurred from each affiliate
- Include the following:
  - product or service received
  - entity providing the product or service
  - payroll and non-payroll amounts
  - expense type to be charged
- The annual total for each Schedule 3 should tie to the appropriate detail budget in the corresponding SEM/SAP Original Budget folder

NEW

Completing the Explanation and Justification of Incremental Positions Schedule

- Prepare a separate schedule for each year 2011 through 2014
- Identify, explain and justify each incremental FPL position associated with changes in annual employment levels as follows
  - Forecasted 2011 increases above the authorized 2011 level
  - Forecasted 2012 increases above the forecasted 2011 level
  - Forecasted 2013 increases above the forecasted 2012 level
  - Forecasted 2014 increases above the forecasted 2013 level
- Provide the gross payroll associated with each incremental position
- Multiples of the same position may be aggregated into one entry
- For the purposes of this schedule, count part time positions as 1.0 each. Do not use the detail budgeting and reporting convention of counting part timers as 0.5 each.

Submitting Completed Supporting Data Schedules

- For the 2012 Planning and Budgeting Cycle, SharePoint will be used to collect all deliverables other than the on-line detail budgets
- Each business unit will have its own folder to deposit the required deliverables
- Further instructions for depositing deliverables are under development and will be included in a revision to this document

Five Year Capital Forecast

NEW

- The Five Year Capital Forecast folder, previously available in SEM/SAP, is no longer a deliverable of the annual planning process.
- The data elements previously provided by the Five Year Capital Forecast will be gathered from the capital detail budgets.
- See below for specific instruction on preparing capital budgets.

Capital Budgeting

<u>General Requirements:</u>

NEW

- Each business unit is required to provide five years of detail capital budgets
  - The Five Year Capital Forecast SEM/SAP folders will no longer be used for capital budgeting
  - The SEM/SAP Business Unit Budget folders will be used to forecast July-December 2011
  - The SEM/SAP Original Budget folders will be used to budget 2012 – 2016
  - See Section 2 – Page 11, "Detail Cash Flow and Work Force Budgeting" for additional information on detail budgeting

REMINDER

- Special requirements
  - Demolition and Removal Costs for a major project
    - ◊ must be budgeted in a separate sub-activity
    - ◊ the words Demolition or Removal must appear in the sub-activity name and description
  - Land Held for Future Use
    - ◊ must be budgeted in a separate budget activity or sub-activity, and
    - ◊ the words Future Use must appear in the activity name and description
  - Units must submit a list of major project retirements
    - ◊ Individual items of property with historical costs of $10 million or more
    - ◊ Identify the month and year (2011 through 2016) of retirement
    - ◊ If none, submit notification indicating nothing to report
  - Asbestos Removal Activity
    - ◊ must be budgeted in a separate budget activity or sub-activity, and
    - ◊ the words Asbestos Removal must appear in the activity name and description
    - ◊ See Accounting Department memo of July 30, 2009 (Section 3 - Appendix)

Completing the Capital Budget

General

- Enter all required information in whole dollars.
- Enter monthly cash flows for all years.
  - For years 2015 and 2016.
    - ◊ Do not budget annual amounts in December
    - ◊ Minor projects may be budgeted using an even monthly spread if better information is not available
    - ◊ Major projects should be cash flowed monthly based on the best information available

Overview

- All capital expenditures are to be forecasted using a budget activity.
  - Capital budget activity (BA) numbers are in the five digit format 0 0 # # # .
  - Under certain circumstances it may be necessary, or desirable, to break a BA into sub-activities.
    - ◊ The capital sub-activity (SA) format is six characters, combining alphas and numerics at the discretion of the business unit.
    - ◊ If no SA is specified, six zeros are assigned as the default SA.
- BAs and SAs are "defined" by certain characteristics.
  - All amounts budgeted under a particular BA or SA must represent expenditures that are consistent with the definition of that BA or SA.
  - The characteristics of a BA or SA include the following:
    - ◊ FERC function code
    - ◊ in-service date
    - ◊ expense type
    - ◊ AFUDC eligibility
    - ◊ depreciable/non-depreciable status
    - ◊ plant site (generation business units and new power plant projects only)
    - ◊ Major / minor designation.
- BAs and SAs are designated as either Major or minor.
  - A specific project is considered a Major project when the total cost over the life of the project is $10 million or more.
    - ◊ A Major project requires a specific BA number unique to the project.
    - ◊ For example, the Canaveral Modernization project is BA 00506.
    - ◊ Stratify a Major project (Major BA) into sub-activities (Major SAs) for the following conditions:

- ➢ when a Major BA comprises individual sub-projects that have individual total life time costs of $10 million or more
- ➢ when the sub-projects have different in-service dates, regardless of their respective sub-project cost
- ➢ to identify demolition or removal costs
- ➢ to identify land held for future use
- ➢ when the business unit finds a further breakdown to be a meaningful way to forecast the project.

- A specific project is considered a minor project when the total cost over the life of the project is less than $10 million.
  - ◊ A minor project may be budgeted under a specific BA, or
  - ◊ A minor project may be grouped with similar capital expenditures under a so called blanket minor BA, such as
    - ➢ BA 00691 (Office Furniture, Fixtures and Equipment), or
    - ➢ BA 00001 (Miscellaneous Forecast Projects).
  - ◊ To forecast minor projects that have the same FERC function
    - ➢ use blanket minor BA 00001, in conjunction with the appropriate SA, per the table below.
    - ➢ **Exception:** The two generation business units need an individual blanket minor for each plant site (see BA Definitions and Plant Site table at the end of this section).
    - ➢ **Caution:** In previous planning cycles, when the Five Year Capital Forecast was still in use, the grouping of numerous minor projects under a single BA/SA was a permitted, expedient means of forecasting capital requirements. When completing the detail capital budgets, the grouping of minor projects should be limited to facilitate active management of the business unit's capital resources.

BA	SA	FERC Function	FERC Function Description
00001	000001	1	Steam Generation
00001	000002	2	Nuclear Generation
00001	000003	3	Other Generation
00001	000004	4	Transmission
00001	000005	5	Distribution-Line
00001	000006	6	Distribution-Substation
00001	000007	7	Buildings
00001	000008	8	General Plant Equipment
00001	000009	9	Transportation Equipment
00001	000010	0	Intangible Plant

- When budgeting any capital expenditures, it is important to ensure that the definition of the BA or SA accurately and adequately describes all of the capital expenditures budgeted or forecasted under that

BA or SA. If not, then the expenditures should be allocated to two or more BAs or SAs as necessary. (See also the Data Confirmation section below).

Data Confirmation

- In order for the Finance Department's financial model to make intelligent use of the forecasted BA/SA cash flows, it must have access to non-quantitative information such as the associated FERC function, in service date, depreciation status, etc.
- All of the non-quantitative information used in the forecast will be obtained directly from the definitions in the BA/SA tables.
- Since the accuracy of the forecast depends on the non-quantitative information being correct, it will be necessary for all units to **perform the following steps prior to the due date** for completing the workbooks (see Calendar Item 11):
  - access the BA/SA Table using the Lotus Notes facility
  - find all of the forecasted capital BAs and SAs
  - confirm the data associated with each of those BAs and SAs is correct
  - if any data in the BA/SA Table is not correct, modify the BA/SA
- The Data Confirmation procedure is not necessary if you are using blanket BA 00001 with the blanket SAs 0000001 through 000010, as they are already correct. Do not attempt to change these BA/SA combinations.
- The BA/SA definition section below may assist you in completing the Data Confirmation step.
  - Function:
    - ◊ The FERC Function. A single digit code describing a classification of expenditures under the FERC System of Accounts. See "Use of the Minor Blanket BA 00001" above for a table of the codes.
  - Depreciation:
    - ◊ "D" if depreciable, "N" if non-depreciable. "A" if amortizable. Land is the only expenditure that is non-depreciable. Land should be in a separate BA or SA with a code of "N."
  - Expense Type:
    - ◊ An alpha code to further describe the type of expenditure within the capital budget type (A = Base, B = ECCR, H = ECRC, use Expense Type A for deferred debits to be capitalized after regulatory approval).
  - Major/Minor:
    - ◊ Capital "M" if Major, blank if minor. A Major BA represents a specific project with a total life of the project cost of $10 million or greater. See the "Overview" section above for further information.

- Plant Site:
  - ◊ A three digit code. Applies primarily to Plant Engineering & Construction, Power Generation and Nuclear. Expenditures pertaining to a specific plant site must be budgeted in a BA or SA unique to that site, per the table on the following page. For all other expenditures use default plant site 000.
- AFUDC:
  - ◊ Indicates eligibility for an accounting treatment known as Allowance for Funds Used During Construction. Used for Major BAs and SAs only. Check with your Accounting Business Unit Representative to make the determination. "Y" if yes. "N" if no.
- In Service Date:
  - ◊ The date the project will be completed and go into service. Used for Major BAs and SAs only. Not applicable for miscellaneous projects under BA 00001.

Listing of Plant Site Codes

Code	Plant Site	Code	Plant Site	Code	Plant Site
010	Cutler	131	Cape Canaveral Modernization	182	Martin #8
040	Riviera #1 & #2	140	Turkey Point Old	185	Martin Gas Pipeline
041	Riviera Modernization	141	Turkey Point #5	186	Martin #7
050	Putnam	146	Turkey Point #6	188	Martin Solar Energy Center
070	Sanford #3	147	Turkey Point #7	190	West County Energy Center #1 & #2
072	Sanford Repowered #4 & #5	148	Turkey Point Common #6 & #7	191	West County Energy Center #3
080	Fort Lauderdale	150	St. Lucie Common	192	Desoto Solar Energy Center
090	Florida EnergySecure Pipeline	151	St. Lucie #1	193	NASA Solar Energy Center
110	Fort Myers Old #1 & #2	152	St. Lucie #2	500	SJRPP #1 & #2
112	Fort Myers Repowered #1 & #2	160	St. Lucie Wind	501	SJRPP Coal Car
113	Fort Myers Peaking Units	170	Manatee #1 and #2	502	SJRPP Switchyard
120	Port Everglades	171	Manatee #3	503	SJRPP Coal Terminal
130	Cape Canaveral	180	Martin #1, #2, #3 & #4	505	Scherer #4

Detail Cash Flow and Work Force Budgeting

REMINDER

General

- The 2012 planning cycle requires the following from each business unit.
- Complete on-line in SEM SAP 2011 Business Unit Budget folder
  - monthly detail cash flows, for all expense types, for the remainder of 2011 (July – December)
- Complete on-line in SEM SAP Original Budget folders 2012 through 2016
  - monthly detail cash flows, for all expense types, for 2012 through 2014
  - monthly detail cash flows, for capital expense types only, for 2015 and 2016
  - a monthly work force detail budget for 2012 through 2014

Cash Flow Detail Budgets

- Monthly detail cash flows will be loaded using the following SEM SAP budgeting elements:
  - Budget Responsibility Code (BRC)
  - Budget activity / Sub-activity (BASA)
  - Expenditure Analysis Code (EAC)
    - ◊ Avoid using EAC Groups to facilitate the conversion to IP SAP
  - Expense Type
- Monthly cash flows are required for all years. When budgeting capital, do not budget annual amounts in December for years 2015 and 2016 (see Capital Budgeting, Section 2 Page 8).
- Enter all expenditures in whole dollars.
- Expense type annual totals should tie to the resource levels approved at the Final Budget Review Meeting on August 17 (see Calendar Item 13).

Work Force Detail Budgets

- A work force detail budget must be prepared for 2012, 2013 and 2014.
- At a minimum, units must prepare the work force detail budget at the business unit level. Units are encouraged to prepare the detail work force budget at lower organization levels to provide adequate support for the 2012 rate case.
- For the following work force types, enter the number of FPL utility employees that will be employed by your business unit, on the last day of each month. (Headcount as of last day of each month.)
  - FEX - FPL Exempt
  - FEP - FPL Exempt Part-Time s (count as 0.5 each)
  - FNX - FPL Non- Exempt
  - FPT - FPL Non-Exempt Part-Time (count as 0.5 Each)
  - FBV - FPL Bargaining Unit Variable
  - FVP - FPL Bargaining Unit Variable Part-Time s (count as 0.5 Each)
  - FBF - FPL Bargaining Unit Fixed
  - FFP - FPL Bargaining Unit Fixed Part-Time (count as 0.5 Each)
  - The December month-end value for each FPL manpower type for each year should tie to resource levels approved at the Final Budget Review Meeting on August 17 (see Calendar Item 13).
- For the following work force types, enter the expected full time equivalent utilization, for each calendar month. (Average headcount over the course of each month.)
  - FET - FPL Exempt Full-Time Temporary
  - FNT - FPL Non-Exempt Full-Time Temporary
  - FFT - FPL Bargaining Unit Fixed Full-Time Temporary
  - FVT - FPL Bargaining Unit Variable Full-Time Temporary
  - FOT - FPL Overtime Equivalent Employees

- TMP - Temporary Non-employee
- CON - Contractor Non-employee
- FTE formula = (total hours to be worked in the month) ÷ (the number of workdays in the month x 8 hours)

REMINDER

- The workforce type monthly budget must have a meaningful relationship to the corresponding expenditure budget for that work force type (e.g. the monthly FEX - FPL Exempt Employees budget should correlate with the monthly EAC 803 cash flow budget).

Payroll

- **Gross Payroll**
  - A unit's gross payroll must be fully budgeted under the appropriate expense types and in the appropriate 800 or 300 level EACs.

NEW

- **Capitalized payroll**
  - 100% of a business unit's capitalized payroll must be budgeted using an 800 level payroll EAC, in one or more of the following expense types: A-Base, B-ECCR, H-ECRC, or M-Miscellaneous.
  - If the capitalized payroll cannot be associated with specific projects, it must be budgeted in generic BASAs that are defined with the appropriate FERC Functions (e.g. 1-Steam Production).

- **Redirected Payroll**
  - Use expense type 7-Redirected Expenses for payroll
    - ◊ allocated to capital through an engineering order,
    - ◊ "cleared" to another charge location within the same business unit, or
    - ◊ "cleared" to another business unit
  - Engineering Order (EO)
    - ◊ EO budgets must be isolated from all other uses of ET-7 to facilitate conversion to IP SAP.
    - ◊ Use dedicated BRCs and BASAs to budget EOs.
  - Payroll "Clearing" within a unit or between units
    - ◊ Use only 800 level payroll EACs in ET-7 for clearing.
    - ◊ Do not budget 400 level EAC offsets; they will be budgeted through programming at the end of the planning process.

REMINDER

    - ◊ ET-7 clearing budgets will not be converted to IP SAP. Therefore, ensure corresponding 300 level payroll EACs are budgeted in an operating or capital expense type at the clearing destination. Otherwise, total company payroll will be understated after conversion.
    - ◊ See also Transfer Out / Transfer In (Section 2 Page 16).

NEW

- **Payroll Overheads**
  - Do not budget for payroll overheads
  - Overheads will be applied programmatically after the conversion of budget details to IP SAP.
  - To ensure payroll overheads will be applied accurately at conversion, it is imperative that a unit's gross payroll is fully budgeted under the appropriate expense types and in the appropriate 800 or 300 level EACs.

NEW

- **Corporate Performance Incentives** (aka EAC 820, PERP or Bonus)
  - Do not budget for the March payout of corporate performance incentives
  - After the conversion of budget details to IP SAP, corporate performance incentives will be applied programmatically as a monthly overhead to all budgeted exempt payroll, EAC 803 and 303.
  - To ensure payroll overheads will be applied accurately at conversion, it is imperative that a unit's gross payroll is fully budgeted under the appropriate expense types and in the appropriate 800 or 300 level EACs.
  - Note: the actual payout of the incentive will be booked to a balance sheet account as a result of a change in accounting treatment; the payout will have no impact on business unit operating or capital budgets.

- **Other Forms of Compensation**
  - To differentiate the payroll associated with hours worked from other forms of compensation, use the following payroll EACs as appropriate:

REMINDER

    - ◊ 809 – Long Term Incentives and Deferred Compensation
    - ◊ 820 – Business Unit level recognition programs only; do not budget for corporate performance incentives
    - ◊ 821 – Payroll - Other Earnings, including employee vacation buys (credit budget)
    - ◊ 822 – Payroll - Lump Sum

NEW

- **Payroll Monthly Cash Flows**
  - Do not budget payroll based on the number of pay period closings per month
  - Budget payroll based on number of work days in each month.
  - A table of the number of work days in each month is included in the 2012 Planning Guideline, Section 3 – Appendix of Schedules and Deliverables
  - Note: the 2011 Planning Guideline discussed the unusual need to budget for a 27th pay period in 2012, one more than usual under the old budgeting scheme. Budgeting by work days per month eliminates this issue entirely.

NEW

Workers Compensation (EAC 760)

- Business units that normally budget for workers compensation premiums should continue to do so.
- At the conclusion of the budget process, when the SEM SAP budget is converted to IP SAP, each workers compensation budget will serve as a cost pool from which the unit's workers compensation premiums will be applied to the unit's payroll as an overhead. The overhead will be unit specific to reflect only the unit's annual premium.

NEW

Outside Counsel for Capital Projects (EAC 691)

- Charges to EAC 691 - Professional Service / Legal for use of outside legal counsel on capital projects will no longer be re-routed to the General Counsel business unit.
- Each business unit should budget for its own expected cost of outside legal counsel for capital projects.

REMINDER

Recruiting and Relocation Costs

- Business units are responsible for their own recruiting and relocation costs.
- Human Resources does not provide funding for these activities.

Expense Types

- Monthly detail cash flows must be prepared for each of the following expense types, as appropriate.
  - **Operating Expenses**
    - ◊ 1-Base O&M
    - ◊ 2-ECCR (Energy Conservation Cost Recovery Clause)
    - ◊ 4-O&M Fuel (Clause)
    - ◊ 5-O&M Capacity (Clause)
    - ◊ 6-Below the Line
    - ◊ 7-Redirected Expenses (see Transfer Out / Transfer In below)
    - ◊ 8-ECRC (Environmental Cost Recovery Clause)
    - ◊ 9-O&M NR Fuel (not recoverable through the Fuel Clause)
    - ◊ G-Inter-company Expenses (see Transfer Out / Transfer In below)
    - ◊ N-Other Expenses
    - ◊ S-Revenue Enhancement Expense
  - **Capital Expenditures**
    - ◊ A-Capital Base
    - ◊ B-Capital ECCR (Energy Conservation Cost Recovery Clause)
    - ◊ H-Capital ECRC (Environmental Cost Recovery Clause)
    - ◊ M-Miscellaneous (To be reclassified to A-Capital Base upon regulatory approval)
    - ◊ V-Revenue Enhancement Capital

- **Revenues**
  - ◊ R-Revenue Enhancement Revenue (budgeted as a credit)

- **Special Notes Regarding Expense Types:**
  - Use of **expense type N** is primarily for stores and materials handling expenses.
  - The assignment of **revenue enhancement expense types S and V** is determined solely by the accounting treatment the actual transaction receives when recorded in the general ledger. Use of expense types S and V is limited to existing revenue enhancement programs in the Engineering and Construction and the Energy Marketing and Trading business units. Business unit proposals for **new revenue enhancement programs** should be submitted to Accounting and Corporate Budgets prior to the commitment of any corporate resources, the implementation of the program, or the inclusion of required resources in the 2012 budgeting and planning deliverables.
  - A unit planning **direct charges to non-utility** entities should budget 100% of its cash expenditures in **expense type G** (see Transfer Out / Transfer In below). The Accounting Department will budget for the recovery of associated corporate overheads.
  - Staff unit expenditures that are **allocable to non-utility** entities through the **Affiliate Management Fee** should be budgeted 100% in **Base O&M**. The Accounting Department will budget for the further allocation of these costs at the corporate level.
  - Units with **unit specific service agreement fee** arrangements should budget both the Base O&M expense and the required offset **in a unique BASA, dedicated to the fee**. The Accounting Department will budget for the recovery of associated corporate overheads.

Transfer Out / Transfer In

- There are three types of transfers employed to plan and track operating expenses that are under the control of one organizational entity, but are budgeted in a different organizational entity.
  - Business Unit to Business Unit
  - Budget Responsibility Code to Budget Responsibility Code (within a business unit)
  - Company to Company
- **Business Unit to Business Unit:** The unit providing the services should make debit entries only in **expense type 7**, using normal payroll and non-payroll EACs. After all detail budgets have been entered and approved, Information Management's Financial Systems group will offset the debit entries by generating credits in expense type 7, using 400 level EACs.
- The unit that will receive the actual costs should budget the appropriate expense type (Base O&M, ECCR, etc), using 300 level EACs for payroll and regular EACs for all non-payroll. It is a **corporate requirement** that all between-unit transfers be budgeted by both the sending and receiving units. (See example A, Section 2, Pages 19 and 20.)

- **Budget Responsibility Code to Budget Responsibility Code:** Within-unit transfers are budgeted in the same manner as unit-to-unit transfers described above, using expense type 7. However, planning and tracking of within-unit transfers is **optional**. A unit may elect to eliminate internal transfers, limit transfers to certain roll-up levels and above, or allow transfers to occur at the BRC level. To ensure the *actual* within-unit transfers will be recorded consistent with the *plan*, contact Information Management's Financial Systems group, and ask them to turn off the transfer mechanism, or reset it to a certain roll-up level. The default setting will create within-unit transfers at the BRC level, which is the lowest possible level. (See example A, Section 2, Pages 19 and 20.)
- **Company to Company:** Direct charges to FPL Group, or any of its subsidiaries, are accomplished by charging an ER 99 work order, or a work order that translates to a subsidiary account. Such charges will be budgeted in a manner similar to the unit-to-unit transfers described above, except that the providing unit will use **expense type G**, instead of expense type 7, and no credit budget will be generated. It is a **corporate requirement** that the unit providing such services budget for all between company transfers. (See example B, Section 2, Page 21.)

Budget Responsibility Code (BRC)

- The Budget Responsibility Code (BRC) is intended to represent an individual (or a position if the position is vacant) with accountability for specific budgeted resources. As a general rule, a BRC should be assigned wherever there is a meaningful level of managerial or supervisory control. Business unit heads, vice presidents, directors, managers and supervisors are likely candidates for individual BRCs.
- The timing of this year's planning cycle runs in parallel with the final stages of the SAP One conversion effort. As such, the SAP Master Data Control Group may provide additional guidance and restrictions on establishing new BRCs during this year's planning cycle.

Budget Activity (BA) and Sub-Activity (SA)

- A Budget Activity (BA) describes a broad category of work performed within the Budget Responsibility Code (BRC). Each BRC is required to have at least one BA. If it is necessary to subdivide the work (BA) further, sub-activities (SA) should be established.
- A BA number is assigned by the budget system and is five numeric characters in length. All BAs have a default sub-BA of 000000. An SA is always six positions in length and may be alpha, numeric, or a combination of both. The business unit may create additional SAs as required.
- A BA should be "in service" indefinitely, or at least until a major change in the nature of the work of the unit (or the BRC) occurs. Do not establish new BAs each year for basic work that continues from year to year. SAs may need to be dropped or added annually, as specific segments of work are completed or started. Otherwise, SAs should be reused each year as much as possible, in the same manner as BAs.

- Avoid establishing BAs or SAs when other budgeting or tracking elements already exist for that purpose. For example, avoid setting up a BA or SA to capture a single EAC. At a minimum, each BA will correspond to at least one work order, often several. If there are a large number of work orders in use, and it is desirable to have a plan for each one, do not establish a separate BA for each work order. Instead use SAs to achieve a one-to-one correspondence with the work orders.
- There is no minimum dollar threshold for the establishment of a BA, nor is there a limit on the maximum number of BAs that a BRC may use. However, to maximize the efficiency of the "engine" (Essbase) that drives the FMIP reporting system, it may be necessary for the Budget Department and/or Information Management's Accounting Systems group to work with a unit that has a disproportionate number of BAs and SAs to the relative size of its budgeted resources. **Note:** special additional rules apply to the establishment of capital BAs (see Section 2 Page 7).
- The timing of this year's planning cycle runs in parallel with the final stages of the SAP One conversion effort. As such, the SAP Master Data Control Group may provide additional guidance and restrictions on establishing new BASAs during this year's planning cycle.

Example A

Transfer-out and Transfer-in

Payroll: Between-units and Within-unit

Example: Unit A plans to spend $600 on exempt payroll (EAC 803), of which, $100 will be charged to unit B.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type 7 (re-directed O&M), which will net to zero. For the transfer-out payroll, a debit will be budgeted by the unit under EAC 803 in expense type 7. After all detail budgets are loaded, Information Systems will generate an offsetting credit in expense type 7 under EAC 403. The receiving unit will budget for the transfer-in payroll under EAC 303 in expense type 1.

This treatment makes it easier for the originating unit to identify its own exempt payroll (expense type 1), its payroll incurred on behalf of others (expense type 7, excluding 400 level EACs), and its gross payroll (sum of 1 and 7, excluding 400 level EACs). Each of the 800 series payroll EACs has a corresponding 400 and 300 series EAC to be used consistent with the example below. (See next page for non-payroll.)

	EAC	Base O&M 1	Redirected O&M 7	Total
Unit A (Originating)	803	500	100	600
	403	-	(100)	(100)
	Total	500	-	500
Unit B (Receiving)	303	100	-	100
	Total	100	-	100
Total Company (Net)	803	500	100	600
	403	-	(100)	(100)
	303	100	-	100
	Total	600	-	600

Example A (continued)

Transfer-out and Transfer-in

Non-Payroll: Between-units and Within-unit

Example: Unit A plans to spend $600 on contractor costs (EAC 662), of which, $75 will be charged to unit B. Unit A will also incur $200 of miscellaneous expenses (EAC 625), of which, $25 will be charged to unit B. In total, unit A will incur $800 of costs, $100 of which will be charged to unit B.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type 7 (re-directed O&M), which will net to zero. For the transfer-out costs, the unit will budget debits in expense type 7, using the regular EACs. After all detail budgets are loaded, Information Systems will generate a single offsetting credit equal to all of the non-payroll EACs in expense type 7. The credit will be entered in EAC 412. The receiving unit will budget for the transfer-in costs under expense type 1, using regular EACs.

Note: The receiving unit should not budget EAC 411 for the transfer-in of non-payroll expenses. EAC 411 is no longer in use for planning purposes, but it will remain active for historical reporting.

		Base O&M	Redirected O&M	
	EAC	1	7	Total
Unit A (Originating)	662	525	75	600
	625	175	25	200
	412	-	(100)	(100)
	Total	700	-	700
Unit B (Receiving)	662	75	-	75
	625	25	-	25
	Total	100	-	100
Total Company (Net)	662	600	75	675
	625	200	25	225
	412	-	(100)	(100)
	Total	800	-	800

Example B

Transfer-out and Transfer-in

Payroll: Between companies only (direct charges to non-utility entities)

Example: Unit A plans to spend $600 on exempt payroll (EAC 803), of which, $100 will be charged to a non-utility entity.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type G (Inter-company O&M). For the transfer-out payroll, a debit will be budgeted by the unit under EAC 803 in expense type G. The budgets of the non-utility entities are separate from the FPL utility budget, so there is no need for Information Systems to generate an offsetting credit in expense type G.

This treatment makes it easier for the originating unit to identify its own exempt payroll (expense type 1), its payroll incurred on behalf of others (expense type G), and its gross payroll (sum of 1 and G). (See next page for non-payroll.)

	Base O&M	Inter-Company O&M	
EAC	**1**	**G**	**Total**
803	500	100	600
Total	500	100	600

Example B (continued)

Transfer-out and Transfer-in

Non-Payroll: Between companies only (direct charges to non-utility entities)

Example: Unit A plans to spend $600 on contractor costs (EAC 662), of which, $75 will be charged to a non-utility entity. Unit A will also incur $200 of miscellaneous expenses (EAC 625), of which, $25 will be charged to non-utility. In total, unit A will incur $800 of costs, $100 of which will be charged to non-utility.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type G (Inter-company O&M). For the transfer-out costs, the unit will budget debits in expense type G, using the regular EACs. The budgets of the non-utility entities are separate from the FPL utility budget, so there is no need for Information Systems to generate an offsetting credit in expense type G.

	Base O&M	Inter-Company O&M	
EAC	1	G	Total
662	525	75	600
625	175	25	200
Total	700	100	800

Performance Measures

General:

REMINDER

- The annual budgeting and planning process requires each business unit to develop and track business unit level performance measures throughout the year.
- All business unit Performance Measures are submitted on a pre-formatted Performance Measure Worksheet maintained by the business unit from year to year. The worksheet features print macros developed in response to senior management's request for different views of the worksheet at different stages of the review and approval process. Units are able to add and delete performance measures per the instructions in the worksheet.

Completing the Performance Measure Worksheet:

- Your submittal should be in the prescribed format, using the pre-formatted Performance Measure Worksheet (see exhibit in the Appendix).
  - Divide your measures into three groups:
    - ◊ operating measures
    - ◊ milestone measures, and
    - ◊ cross-functional measures.
- In your initial submittal:
  - Provide actual performance for 2006 through 2010
  - Provide a year-end estimate versus your current 2011 targets.
  - Identify your proposed measures and targets for 2012 through 2014.
  - Note: your business unit's Budget Presentation will include a discussion of performance measures; however, the actual Performance Measure Work Sheet is not due until Wednesday, November 30 (see Calendar Item 16).
- In your final submittal:
  - Provide a year-end actual versus your current 2011 targets.
  - Include your approved measures and targets for 2012 through 2014.
  - Due date to be determined, tentatively end of first week in January

NEW

Submitting the Performance Measure Worksheet:

- For the 2012 Planning and Budgeting Cycle, SharePoint will be used to collect all deliverables other than the on-line detail budgets
- Each business unit will have its own folder to deposit the required deliverables
- Further instructions for depositing deliverables are under development and will be included in a revision to this document

Accessing Planning and Budgeting Deliverables from Previous Planning Cycles

REMINDER

General

- In previous planning cycles, a shared directory was used to collect planning and budgeting deliverables from the business units.
- Deliverables that were placed on the shared directory during the 2011 Planning and Budgeting Process are accessible on the path **\\GOXSF01\GOFIN$\BUDGETS\perf1011\unit**, where **unit** is the abbreviation for your business unit (e.g. **im** for Information Management).
- Similarly, deposited deliverables from the 2010 Planning and Budgeting Process may be accessed on the path **\\GOXSF01\GOFIN$\BUDGETS\perf0910\unit,** and so on.
- Do not place 2012 Planning and Budgeting Process deliverables in shared directories designated for previous planning cycles; use SharePoint (instructions under development).

Connecting to your shared directory

- To access your unit's shared directory, open **Windows Explorer**, click on **Tools,** and then click on **Map Network Drive**. Map an available drive to **\\GOXSF01\GOFIN$\BUDGETS.** (Note: the Path is not case sensitive.).
- All of the folders in **\\GOXSF01\GOFIN$\BUDGETS** will be listed; however, you will only have access to your business unit's directory.
- Access to your unit's directory is based on an approved SLID ID.
- It is suggested that the number of individuals authorized to access this directory be kept to a minimum, as a means of controlling current versions of documents.
- To request access to your unit's directory
  - Contact the Information Management Support Center (HELP Desk)
    - http://infpl/bunit/im/imsc/index.shtml, or
    - 305-552-4357 / 305-552-HELP
  - Request Read / Write access to the complete path. Example:
    - for Power Generation: \\GOXSF01\GOFIN$\BUDGETS**perf1011\PwrGen**
  - Provide the name of the individual, the SLID ID and the business unit to be accessed
  - The Information Management Support Center will contact Dan Reilly, Corporate Budgets Manager, for final approval
  - Once approved, the SLID will have access to all prior year folders for the unit
    - example: \\GOXSF01\GOFIN$\BUDGETS**perf0809\PwrGen**

Preparation of Selected Rate Case Deliverables

REMINDER

MFRs C-15 and C-16

- Preparation for the upcoming rate case will require the development of a set of schedules known as Minimum Filing Requirements (MFRs).
- Two MFRs in particular require data below the level of detail at which we budget.
  - MFR C-15 Industry Association Dues
    - ◊ requires the identification of entities to whom dues are paid
    - ◊ makes no distinction between O&M or Capital
    - ◊ does not include entities budgeted as Below the Line.
  - MFR C-16 Outside Professional Services
    - ◊ requires the identification of entities from whom services are received
    - ◊ requires a distinction between O&M or Capital
- Examples of both MFRs from the last rate case are provided at the end of the Appendix (see Excel file: FPL_2012_PlngProc_Sec3_Apndx.xls).
- Both of the MFRs need to be completed for the so called test year, which corresponds to the 2013 budget.
- In anticipation of needing to provide the level of detail shown in the examples, business units should gather the required level of detail while preparing their detail budgets. Because MFR C-16 has a high threshold for reporting, which cannot accurately be determined until the entire company operating budget is approved, units should use the $1,000,000 threshold, per the MFR's instructions.
- After the conclusion of the planning and budgeting process, Regulatory Affairs will be coordinating the development of these MFRs and will contact the units with more specific instructions regarding the submittal of the required information.

Florida Power & Light Company

2012 Planning Process

Guideline

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Section 3

Appendix
of
Schedules and References

Base O&M
Business Unit: ______________________
($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Project / Activity 4								
Project / Activity 5								
Project / Activity 6								
Project / Activity 7								
Project / Activity 8								
Project / Activity 9								
Project / Activity 10								
Total Base O&M								

Below the Line
Business Unit: ____________________
($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Project / Activity 4								
Project / Activity 5								
Project / Activity 6								
Project / Activity 7								
Project / Activity 8								
Project / Activity 9								
Project / Activity 10								
Total Below the Line O&M								

Total Capital
Business Unit: ____________________

($millions) or ($thousands)

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Performance Measure Impacted
Base Capital								
Project / Activity 1								
Project / Activity 2								
Project / Activity 3								
Total Base Capital								
Conservation Clause								
Project / Activity 4								
Environmental Clause								
Project / Activity 5								
Total Clause Capital								
Total Capital								

FPL Employees / Gross Payroll
Business Unit: ____________________

Project / Activity	2009 Actual	2010 Actual	2011 Budget	2011 Approved	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast
Full Time (excluding Temporaries)								
FPL Exempt								
FPL Non-Exempt								
FPL Bargaining Unit								
Total FPL Full Time Employees								
Part Time (count each as 1.0)								
FPL Exempt								
FPL Non-Exempt								
FPL Bargaining Unit								
Total FPL Part Time Employees								
Total FPL Employees (excluding Temporaries)								
Gross Payroll								
(Includes Regular, Overtime, Unit Recognition Progs,								
(Lump Sum, Other Earnings, and LTI / Deferred Comp)								

Affiliate Management Fee Pools
Business Unit: ______________________

($millions) or ($thousands)

Project / Activity	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Drivers
Project / Activity 1							
Project / Activity 2							
Project / Activity 3							
Project / Activity 4							
Project / Activity 5							
Total AMF Pools							

Service Fees and Direct Charges
Business Unit: ______________________

($millions) or ($thousands)

Project / Activity	2010 Actual	2011 Budget	2011 Forecast	2012 Request	2013 Forecast	2014 Forecast	Charged To (check box)		
							NextEra Energy, Inc. (Corporate)	NextEra Energy Resources	Other (FiberNet, FPLES, etc)
Service Fees									
Project / Activity 1									
Project / Activity 2									
Total Service Fees									
Direct Charges									
Project / Activity 3									
Project / Activity 4									
Total Direct Charges									

FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO. 120015-EI
MFR NO. F-05
ATTACHMENT 8 OF 9

Schedule 1 - Charges to Other Business Units
2011 Forecast
Business Unit: ____________________ Prepared By: ____________
Financial Data in Thousands

Business Unit to Incur Costs	Expense Type 7 Redirected Expenses Payroll	Non-payroll	Process / Activity
Corporate Financial			
Customer Service	$ 10,500	$ 5,300	Programming support for ...
Distribution	$ 20,350	$ 10,400	Programming support for ...
Energy Marketing and Trading			
Engineering, Construction & Corporate Svcs			
External Affairs			
FPL Financial			
General Counsel			
Governmental Affairs - Federal			
Governmental Affairs - State			
Human Resources			
Information Management			
Internal Audit			
Marketing & Communications			
Nuclear Division			
Power Generation Division			
Project Development			
Regulatory Affairs			
Resource Assessment & Planning			
Strategy & Policy			
Transmission			
Location - 10			
Total (must agree SEM/SAP Original Budget detail cash flows)	$ 30,850	$ 15,700	

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Schedule 1 - Charges to Other Business Units
2012 Funds Request
Business Unit: ____________________ Prepared By: ____________
Financial Data in Thousands

Business Unit to Incur Costs	Expense Type 7 Redirected Expenses Payroll	Non-payroll	Process / Activity
Corporate Financial			
Customer Service	$ 10,500	$ 5,300	Programming support for ...
Distribution	$ 20,350	$ 10,400	Programming support for ...
Energy Marketing and Trading			
Engineering, Construction & Corporate Svcs			
External Affairs			
FPL Financial			
General Counsel			
Governmental Affairs - Federal			
Governmental Affairs - State			
Human Resources			
Information Management			
Internal Audit			
Marketing & Communications			
Nuclear Division			
Power Generation Division			
Project Development			
Regulatory Affairs			
Resource Assessment & Planning			
Strategy & Policy			
Transmission			
Location - 10			
Total (must agree SEM/SAP Original Budget detail cash flows)	$ 30,850	$ 15,700	

FLORIDA POWER & LIGHT COMPANY
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Schedule 1 - Charges to Other Business Units
2013 Funds Request
Business Unit: ____________________ Prepared By: ____________
Financial Data in Thousands

Business Unit to Incur Costs	Expense Type 7 Redirected Expenses Payroll	Non-payroll	Process / Activity
Corporate Financial			
Customer Service	$ 10,500	$ 5,300	Programming support for ...
Distribution	$ 20,350	$ 10,400	Programming support for ...
Energy Marketing and Trading			
Engineering, Construction & Corporate Svcs			
External Affairs			
FPL Financial			
General Counsel			
Governmental Affairs - Federal			
Governmental Affairs - State			
Human Resources			
Information Management			
Internal Audit			
Marketing & Communications			
Nuclear Division			
Power Generation Division			
Project Development			
Regulatory Affairs			
Resource Assessment & Planning			
Strategy & Policy			
Transmission			
Location - 10			
Total (must agree SEM/SAP Original Budget detail cash flows)	$ 30,850	$ 15,700	

FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
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ATTACHMENT 8 OF 9
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Schedule 1 - Charges to Other Business Units
2014 Funds Request
Business Unit: ____________________ Prepared By: ____________
Financial Data in Thousands

Business Unit to Incur Costs	Expense Type 7 Redirected Expenses Payroll	Non-payroll	Process / Activity
Corporate Financial			
Customer Service	$ 10,500	$ 5,300	Programming support for ...
Distribution	$ 20,350	$ 10,400	Programming support for ...
Energy Marketing and Trading			
Engineering, Construction & Corporate Svcs			
External Affairs			
FPL Financial			
General Counsel			
Governmental Affairs - Federal			
Governmental Affairs - State			
Human Resources			
Information Management			
Internal Audit			
Marketing & Communications			
Nuclear Division			
Power Generation Division			
Project Development			
Regulatory Affairs			
Resource Assessment & Planning			
Strategy & Policy			
Transmission			
Location - 10			
Total (must agree SEM/SAP Original Budget detail cash flows)	**$ 30,850**	**$ 15,700**	

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Schedule 2 - Charges to Affiliates
2011 Forecast
Business Unit: ____________________ **Prepared By:** ____________________
Financial Data in Thousands

Description of Product / Service Provided	Affiliate Receiving Charges																	
	Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	1,500	300	1,800	500	[redacted]	500	-	-	-	-	-	-	-	-	-	2,000	300	2,300
Service Agreement Fee [1] [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	20	120
Total Non-Utility Support Provided	1,500	300	1,800	600	20	620	-	-	-	-	-	-	-	-	-	2,100	320	2,420

READ COMMENTS AND NOTES BELOW PRIOR TO COMPLETING SCHEDULE

COMMENTS-

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Schedule 2 - Charges to Affiliates
2012 Funds Request
Business Unit: ______________________ Prepared By: ___________________
Financial Data in Thousands

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	Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	1,500	300	1,800	500	[redacted]	500	-	-	-	-	-	-	-	-	-	2,000	300	2,300
Service Agreement Fee [1] [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	20	120
Total Non-Utility Support Provided	1,500	300	1,800	600	20	620	-	-	-	-	-	-	-	-	-	2,100	320	2,420

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Schedule 2 - Charges to Affiliates
2013 Funds Request
Business Unit: ______________________ **Prepared By:** ___________________
Financial Data in Thousands

Description of Product / Service Provided	Affiliate Receiving Charges																	
	Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	1,500	300	1,800	500	[redacted]	500	-	-	-	-	-	-	-	-	-	2,000	300	2,300
Service Agreement Fee [1] [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	20	120
Total Non-Utility Support Provided	1,500	300	1,800	600	20	620	-	-	-	-	-	-	-	-	-	2,100	320	2,420

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Schedule 2 - Charges to Affiliates
2014 Funds Request
Business Unit: ______________________ **Prepared By:** ____________________
Financial Data in Thousands

Description of Product / Service Provided	Affiliate Receiving Charges																	
	Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300			-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-		-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500		500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	1,500	300	1,800	500		500	-	-	-	-	-	-	-	-	-	2,000	300	2,300
Service Agreement Fee [1] [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	20	120
Total Non-Utility Support Provided	1,500	300	1,800	600	20	620	-	-	-	-	-	-	-	-	-	2,100	320	2,420

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Schedule 3 - Charges from Affiliates
2011 Forecast
Business Unit: **Prepared By:**
Financial Data in Thousands

		Affiliate Providing Products / Services [1]																	
		Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
Description of Product / Service Provided	Expense Type	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

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FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO. 120015-EI
MFR NO. F-05
ATTACHMENT 8 OF 9
PAGE 56 OF 67

Schedule 3 - Charges from Affiliates
2012 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Expense Type	Affiliate Providing Products / Services [1]																	
		Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
		Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

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Schedule 3 - Charges from Affiliates
2013 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Expense Type	Affiliate Providing Products / Services [1]																	
		Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
		Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

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Schedule 3 - Charges from Affiliates
2013 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Expense Type	Affiliate Providing Products / Services [1]																	
		Group Capital			NextEra Energy [2]			Fibernet			FPLES			Palms			Total		
		Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

<u>READ COMMENTS AND NOTES BELOW PRIOR TO COMPLETING SCHEDULE</u>

COMMENTS-

Break out payroll and non-payroll items separately as loadings are only added to payroll and errors in the type of expense will result in incorrect loadings being budgeted.

If Business Unit interacts with NextEra nuclear plants, identify costs separately by plant by using the multiple item lines provided.

NOTES-

[1] Include overheads and loadings only on Payroll amounts.

[2] Include charges from Seabrook, Duane Arnold, and Point Beach, if any.

Explanation and Justification of Incremental Positions

Business Unit: ____________________ **Year:** __________

	Type (1)	Position Title	Qty	Est. Gross Payroll ($000)	Explanation and Justification
1	FEX	Manager of ...	1	$85,000	Management of .....
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					

(1) Types (count all positions as 1.0 each, do not enter fractional amounts)

FEX - FPL Exempt
FEP - FPL Exempt Part-Time
FET - FPL Exempt Full-Time Temporary

FNX - FPL Non- Exempt
FPT - FPL Non-Exempt Part-Time
FNT - FPL Non-Exempt Full-Time Temporary

FBF - FPL Bargaining Unit Fixed
FFP - FPL Bargaining Unit Fixed Part-Time
FFT - FPL Bargaining Unit Fixed Full-Time Temporary

FBV - FPL Bargaining Unit Variable
FVP - FPL Bargaining Unit Variable Part-Time
FVT - FPL Bargaining Unit Variable Full-Time Temporary

2011 - 2012 FPL CORPORATE INCENTIVE PLAN PERFORMANCE MEASURES

BUSINESS UNIT NAME HERE

WGT '11	WGT '12	PERFORMANCE MEASURES	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	2011 YEAR END TARGET	2011 YEAR END ESTIMATE	ON TARGET YEAR END? (1)	COMMENTS (2)	TARGET 2012	FORECAST 2013	FORECAST 2014	ORG LEVEL (3)	2012 STRETCH TARGET (4)
75%	75%	**OPERATING MEASURES**														
		Base O&M ($MM)	$8.8	$9.0	$9.5	$10.0	$10.5	$10.0	$9.5	Better		$9.8	$9.6	$9.4	Corp	Yes
		Capital ($MM)	$15.0	$12.0	$11.0	$10.0	$10.0	$9.0	$10.0	Worse	unplanned expenditures	$8.8	$8.2	$8.2	Corp	
		Total Full Time Equivalent Employees (FPL & All Others)	95	97	97	99	100	100	100	Target		100	100	101	Corp	
25%	25%															
		Number of incidents	8	9	10	10	11	10	8	Better		8	8	8	Unit	
		Frequency of occurrences	7	5	5	6	4	4	5	Worse	ineffective measures	3	3	3	Unit	Yes
		MILESTONE MEASURES														
		Completion of work on project "A" by year end						12/06	11/06	Better					Unit	
		Completion of project "B" by end of 3Q 2007										8/05			Unit	
		CROSS-FUNCTIONAL MEASURES														
		None														

NOTE 1: indicate either Better, Worse or Target
NOTE 2: comments required if Estimate is Worse than Target
NOTE 3: indicate level of organization this indicator is recommended for 2011: Corp or Unit.
NOTE 4: indicate "Yes" if this a stretch target for 2012.

SAMPLE ONLY
DO NOT SUBMIT - UPDATE PRE-FORMATTED SHEET FROM LAST YEAR

	Number of Working Days Per Month												Total Days
	January	February	March	April	May	June	July	August	September	October	November	December	
2011	21	20	23	21	22	22	21	23	22	21	22	22	260
2012	22	21	22	21	23	21	22	23	20	23	22	21	261
2013	23	20	21	22	23	20	23	22	21	23	21	22	261
2014	23	20	21	22	22	21	23	21	22	23	20	23	261
2015	22	20	22	22	21	22	23	21	22	22	21	23	261
2016	21	21	23	21	22	22	21	23	22	21	22	22	261

Number of Working Days Per Month						
	2011	2012	2013	2014	2015	2016
January	21	22	23	23	22	21
February	20	21	20	20	20	21
March	23	22	21	21	22	23
April	21	21	22	22	22	21
May	22	23	23	22	21	22
June	22	21	20	21	22	22
July	21	22	23	23	23	21
August	23	23	22	21	21	23
September	22	20	21	22	22	22
October	21	23	23	23	22	21
November	22	22	21	20	21	22
December	22	21	22	23	23	22
Total Days	260	261	261	261	261	261

FPL

TO:	FPL Business Units	**DATE:**	7/30/09
FROM:	Accounting Department	**LOCATION:**	ACG/JB
SUBJECT:	Accounting Process for Asbestos Removal Activities	**COPIES TO:**	Dave Huss Don Moss Laura Fowler Dan Reilly Melissa Linton Martin Garmendia Ken Huff

Purpose:
The purpose of this memo is to document the process that FPL's Business Units should follow to budget and account for asbestos removal activities. This process is effective January 1, 2010.

Background
Implementation of FIN 47:
In 2005, FPL adopted FIN 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* (FIN 47), which required asbestos removal activities to be accounted for as asset retirement obligations (AROs). Previously, amounts related to asbestos removal activities were included in the dismantlement reserve, and the current portion was included in the environmental liability reserve (ELR). Upon adoption of FIN 47, FPL reclassified approximately $2.6 million (currently less than $100K) of estimated asbestos removal costs from the ELR to an ARO account 230.205 (i.e., "Historical ARO"). This amount was transferred to the ARO based on the current estimated cost of removal rather than a fair value measurement, since the asbestos was expected to be removed within a short time period (1-2 years). In addition to the $2.6M reclassified from the ELR, PGD Environmental Services identified asbestos removal costs at the fossil plants that are expected to occur when dismantlement occurs, at the end of plant life, which are also included in the ARO. As required by FAS 143, this amount was recorded at fair value (i.e., current removal costs were inflated to the date the dollars were expected to be expended, and then discounted back to 2005, using a credit-adjusted risk free rate).

Current Responsibilities:
Each FPL Business Unit (BU) is responsible for tracking and recording costs related to ARO activities. BUCs work orders are used to record the actual costs incurred to remove the asbestos, and they are specific to the plant location and unit. These work orders currently translate to the ARO account for Fossil (230.291), Distribution (230.294), or Nuclear (230.293). No costs incurred to remove the asbestos are being charged to operations and maintenance expense by the BUs.

Currently, Regulatory Accounting is responsible for ensuring that the asbestos removal charges made against the ARO accounts by the BUs are properly reflected in the ARO liability for GAAP reporting purposes each reporting period. Additionally, Regulatory Accounting ensures that these charges are properly reflected as reductions in the dismantlement and/or cost of removal. Environmental Services no longer has budget responsibility for the reserve related to AROs.

New Accounting Process:
Responsibility of Business Units:
Beginning on 1/1/2010, FPL BUs will be required to follow a new process to account for costs related to asbestos removal activities. This process requires that the BUs charge all asbestos removal activities related to both Capital and O&M projects to Account 108.332 – removal cost dismantlement (Fossil Plants) or 108.300 – removal cost (Nuclear Plants and others) as applicable. Use of accounts 230.291, 230.293, and 230.294 should be discontinued effective 1/1/2010. The BUs will be responsible to ensure that the work order used for an asbestos removal project translates to account 108.332 or 108.300, as applicable. Like the current process (prior to 1/1/2010), the BUs will not charge O&M expense for costs incurred to remove the asbestos.

Responsibility of Forecasting and Budgeting:
In August 2009, *Corporate Budgets* will distribute 2010 budget instructions to the BUs regarding the proper budgeting for all asbestos removal activities. Based on these instructions, the BUs will be responsible to account for the cost of asbestos removal in their capital budgets.

Responsibility of Environmental Services:
Environmental Services (ES) will have no budget or accounting responsibility related to the removal of asbestos. However, because asbestos removal is an environmental issue, ES will still need to be involved at the appropriate level on these types of projects.

Responsibility of PGD Environmental Service:
PGD Environmental Services will continue to be responsible for providing to accounting the total remaining exposure by plant on a quarterly basis.

Responsibility of Regulatory Accounting:
Regulatory Accounting will continue to be responsible for ensuring that the asbestos removal charges made to Account 108.332 and 108.300 by the BUs are properly reflected in the ARO liability, as well as the Asset Retirement Cost. Additionally, Regulatory Accounting will be responsible for determining whether these charges are consistent with the total ARO estimate provided by PGD Environmental Services each reporting period (see above).

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: Provide a schedule of industry association dues included in cost of service by organization for the test year and the most recent historical year. Indicate the nature of each organization. Individual dues less than $10,000 may be aggregated.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/10
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___
Witness: Robert E. Barrett Jr., J.A. Stall, Kathleen Slattery, Michael G. Spoor, James A. Keener, Dr. Rosemary Morley, Marlene M. Santos

Line No.	[1] Name and Nature of Organization	[2] Electric Utility ($000's)	[3] Jurisdictional Factor	[4] Jurisdictional Amount ($000's)
1	Business Roundtable (Professional)	80	0.99175	79
2	(EEI) Edison Electric Institute (Professional)	1,910	0.99175	1,894
3	(FGG) Florida Electric Power Coordination Group (Professional)	77	0.99175	76
4	(FRCC) Florida Reliability Coordinating Council (Professional)	1,270	0.99175	1,259
5	(NERC) North American Elec. Reliab. Coord. Council (Professional)	2,821	0.99175	2,798
6	(SEE) Southeastern Electric Exchange (Professional)	63	0.99175	62
7	Investment Enterprise (Technical/Professional)	52	0.99175	52
8	Center for Energy Workforce Development (General Management)	26	0.99175	26
9	William J Clinton Foundation (Community Development)	26	0.99175	26
10	United States Climate Action Partnership (USCAP) (National Policy Development)	125	0.99175	25
11	The Conference Board (General Management)	54	0.99175	54
12	Florida Chamber of Commerce (Community Development)	38	0.99175	38
13	US Chamber Annual Education Fund (Community Development)	84	0.99175	83
14	HR Policy (Professional)	16	0.99175	16
15	Utility water Activities Group (UWAG) (Professional)	142	0.99175	141
16	Utility Solid Waste Act Group (USWAG) (Professional)	130	0.99175	129
17	MJ Bradley (Clean Energy Group) (Professional)	64	0.99175	63
18	Citation Publishing (Professional)	65	0.99175	64
19	Customer Contact Council (Professional)	35	0.99175	35
20	Food Marketing Institute (General Management)	12	0.99175	12
21	Saratoga Institute (Technical/Professional)	20	0.99175	20
22	Central Florida Health Care Coalition (Professional)	10	0.99175	10
23	National Business Group on Health (Professional)	12	0.99175	12
24	Equal Employment Advisory Council	11	0.99175	11
25	National Energy Regulatory Commission (Professional)	40	0.99175	40
26	NEETRAC Georgia Tech Research (Professional)	26	0.99175	26
27	Center for Energy Advancement through Technological Innovation (CEATI) (Professional)	34	0.99175	34
28	(INPO) Institute of Nuclear Power Operations	3,414	0.99175	3,386
29	(NEI) Nuclear Energy Institute (Technical/Professional)	1,201	0.99175	1,191
30	(EUCG) Electric Utility Cost Group (Professional)	14	0.99175	14
31	(EPRI) Electric Power Research Institute (Professional)	2,458	0.99175	2,438
32	Curtis Wright / Readily Accessible Parts & Inventory Database (RAPID) memb. Fee (Professional)	55	0.99175	55
33	International Stds. & Spec. Database (HIS) memb. Fee (Professional)	11	0.99175	11

Supporting Schedules: F-8 Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: Provide a schedule of industry association dues included in cost of service by organization for the test year and the most recent historical year. Indicate the nature of each organization. Individual dues less than $10,000 may be aggregated.

Type of Data Shown:
X Projected Test Year Ended 12/31/10
___ Prior Year Ended ___/___/___
___ Historical Test Year Ended ___/___/___
Witness: Robert E. Barrett Jr., J.A. Stall, Kathleen Slattery, Michael G. Spoor, James A. Keener, Dr. Rosemary Morley, Marlene M. Santos

Line No.	[1] Name and Nature of Organization	[2] Electric Utility ($000's)	[3] Jurisdictional Factor	[4] Jurisdictional Amount ($000's)
1	Esource (Technical/Professional)	68	0.99175	67
2	Electrical Council of Florida (Technical/Professional)	14	0.99175	14
3	Greater Miami Chamber of Commerce (Business Organization)	32	0.99175	32
4	Miami Dade Beacon Council (Business Organization)	17	0.99175	17
5	Greater Fort Lauderdale Chamber of Commerce (Business Organization)	22	0.99175	22
6	The Chamber of Southwest Florida (Business Organization)	14	0.99175	14
7	The Center for Corporate Citizenship (Business Organization)	10	0.99175	10
8	Miami Beach Chamber of Commerce (Business Organization)	10	0.99175	10
9	Latin Chamber of Commerce (Business Organization)	10	0.99175	10
10	Business Development (Business Organization)	10	0.99175	10
11	CIO Executive Board Membership (Professional)	46	0.99175	46
12	United Telecomm Company (Professional)	13	0.99175	13
13	UNITE Utility Consortium (Professional)	54	0.99175	54
14				
15	**Dues Less Than $10,000 Aggregate:**	407	0.99175	404
16				
17	**Total Industry Association Dues:**	15,123		14,873
18				
19	**Average Number of Customers:**	4,548,763		4,548,759
20				
21	**Dues Per Customer:**	$3.32		$3.27
22				
23	**Lobby Expenses:**	$0.00		$0.00
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				

Supporting Schedules: F-8 Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: Provide the following information regarding the use of outside professional services during the test year. Segregate the services by types such as accounting, financial, engineering, legal or other. If a projected test period is used, provide on both a projected and a historical basis for services exceeding the greater of $1,000,000 or .5% (.005) of operation and maintenance expenses.

Type of Data Shown:
__X__ Projected Test Year Ended _1
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/
Witness: J.A. Stall, Christopher A. Ber

Line No.	Type of Service or Vendor	Description of Service(s)	Account(s) Charged	Test Year Costs (000)	
1					
2					
3	**Accounting**				
4	None over the threshold				
5					
6					
7	**Financial**				
8	None over the threshold				
9					
10	**Engineering**				
11	AREVA Total	Engineering Services, Outage Services	Various Capital & O&M (1)	$25,708	
12	Guidant Total	Engineering Services	Various Capital & O&M (1)	$25,400	
13	TBD Total	Alloy 600 repair services	Various Capital & O&M (1)	$24,900	
14	TBD Total	Independent Fuel Storage Site Work, Fire Protection Project,	Various Capital & O&M (1)	$15,592	
15		Engineering & Construction Support			
16	Williams Total	Engineering & Construction Support	Various Capital & O&M (1)	$8,120	
17					
18	**Legal**				
19	None over the threshold				
20					
21	**Other (specify)**				
22	Regulated Security Solutions (RSS)	Security Services	524	$16,538	
23	Day & Zimmerman NPS Total	Construction Support	Various Capital & O&M (1)	$89,441	
24	IBM CORPORATION	FENA Program Professional Services	Mostly Capital	$2,470	
25	IBM CORPORATION	Mainframe/Servers SW & HW Maint. and Support Services	O&M	$7,600	
26	TBD	Professional Services for CISIII Implementation	Various Capital & O&M	$10,000	
27					
28	**Uprate Project Included Nuclear Cost Recovery Docket**				
29	Siemens	Engineering & Construction Support	Various Capital	$122,467	
30	Tei	Engineering & Construction Support	Various Capital	$19,129	
31	Bechtel	Engineering, Procurement & Construction	Various Capital	$85,416	
32					
33					
34					
35					
36	**Total Outside Professional Services**				$452,781
37					=========
38	(1) Amounts include other contractor labor costs. Outside professional service costs cannot be separately identified for this vendor in the test period.				

Supporting Schedules: Recap Schedules: C-12

FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO. 120015-EI
MFR NO. F-05
ATTACHMENT 8 OF 9
PAGE 67 OF 67

2012 Planning and Budgeting Process Calendar

Item	Date	Day	Action / Deliverable / Event	Comment / Reference
1	9-Apr	Fri	Planning Assumptions and Guidelines issued.	Provided by Corporate Budgets.
2	11-Apr	Mon	Units begin to develop 2012-2014 O&M budgets and 2012-2016 Capital Budgets.	Guidance given by Corp Budgets.
3	27-May	Fri	Units submit Budget Presentation to Corp Budgets in advance of Armando Olivera (AJO) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
4	9-Jun	Thur	**Armando Olivera Budget Review Meeting** Business units present to AJO & Budget Review Committee.	Applies to certain business units. See Section 1, Page 8.
5	27-Jun	Mon	Units submit Budget Presentations to Corp Budgets in advance of Jim Robo (JR) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
6	1-Jul	Fri	Those business units with budget activities related to the Affiliate Management Fee, Affiliate Service Fees, or Affiliate Direct Charges, load all budget details for those budget activities, for 2012-2014.	Applies to all business units. See Section 2, Page 3.
7	8-Jul	Fri	**Benchmark:** business unit detail budgets for all required periods should be substantially complete in SEM SAP.	No deliverable at this time. See Item 11.
8	11-Jul	Mon	AJO review of the current status of 2012 Plan with Corp Budgets prior to the 7/14 JR meeting.	No unit participation required at this time.
9	13-Jul	Wed	All business units load all budget details, for all expense types, for the remaining months of 2011.	Applies to all business units. See Section 2, Page 3.
10	14-Jul	Thur	**Jim Robo Budget Review Meeting** Corp Budgets presents to JR, AJO & Budget Review Committee.	No unit participation required at this time. See Section 1, Page 8.
11	22-Jul	Fri	All business units load all **final** budget details, for all expense types and work force, for 2012-2014. All business units load all **final** budget details, for all capital expense types, for 2015-2016. All business units submit all **final** required supporting schedules, for 2012-2014.	Applies to all business units. See Section 2, Pages 2-3.
12	3-Aug	Wed	Units submit **final** Budget Presentations to Corp Budgets in advance of Lew Hay (LH) Budget Review Meeting.	Applies to all business units. See Section 1, Pages 1-6.
13	17-Aug	Wed	**Lew Hay Budget Review Meeting** FPL Final Budget Review Mtg with LH, JR, AJO & Budget Review Committee.	No unit participation required at this time. See Section 1, Page 9.
14	22-Aug	Mon	If necessary, all business units update all deliverables submitted on July 22 (Item 11 above)	Applies to all business units. See Section 2, Pages 2-3.
15	31-Aug	Wed	If necessary, all business units update Budget Presentations submitted on August 3 (Item 12 above)	Applies to all business units. See Section 1, Page 9
16	30-Nov	Wed	All business units submit updated Performance Measure sheets	Applies to all business units. See Section 2, Page 3.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

(1)
Model : Net Energy for Load

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Total Customers	10%	Net Energy For Load	10.00%	
2	Total Customers	-10%	Net Energy For Load	-10.00%	
3	Heating Degree Days	10%	Net Energy For Load	0.13%	0.013
4	Heating Degree Days	-10%	Net Energy For Load	-0.13%	0.013
5	Cooling Degree Hours	10%	Net Energy For Load	2.29%	0.229
6	Cooling Degree Hours	-10%	Net Energy For Load	-2.29%	0.229
7	Heating Degree Days based on 45 degrees	10%	Net Energy For Load	0.01%	0.001
8	Heating Degree Days based on 45 degrees	-10%	Net Energy For Load	-0.01%	0.001
9	CPI Energy	10%	Net Energy For Load	-0.32%	-0.032
10	CPI Energy	-10%	Net Energy For Load	0.32%	-0.032
11	Florida Real per Capita Income	10%	Net Energy For Load	1.52%	0.152
12	Florida Real per Capita Income	-10%	Net Energy For Load	-1.52%	0.152
13	Weather Sensitive Energy Efficiency Standards	10%	Net Energy For Load	-0.11%	-0.011
14	Weather Sensitive Energy Efficiency Standards	-10%	Net Energy For Load	0.11%	-0.011
15	Inactive Ratio	10%	Net Energy For Load	-0.69%	-0.069
16	Inactive Ratio	-10%	Net Energy For Load	0.69%	-0.069
17					
18					
19					
20					
21					
22					
23					
24					
25					

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

(1)
Model : Residential Sales

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Residential Customers	10%	Residential Sales	10.00%	
2	Residential Customers	-10%	Residential Sales	-10.00%	
3	Heating Degree Hours	10%	Residential Sales	0.44%	0.044
4	Heating Degree Hours	-10%	Residential Sales	-0.44%	0.044
5	Heating Degree Hours (Lagged One Month)	10%	Residential Sales	0.17%	0.017
6	Heating Degree Hours (Lagged One Month)	-10%	Residential Sales	-0.17%	0.017
7	Cooling Degree Hours	10%	Residential Sales	2.05%	0.205
8	Cooling Degree Hours	-10%	Residential Sales	-2.05%	0.205
9	Cooling Degree Hours (Lagged One Month)	10%	Residential Sales	1.18%	0.118
10	Cooling Degree Hours (Lagged One Month)	-10%	Residential Sales	-1.18%	0.118
11	Florida Real per Capita Income	10%	Residential Sales	3.67%	0.367
12	Florida Real per Capita Income	-10%	Residential Sales	-3.67%	0.367
13	Real Gasoline Price (Lagged One Month)	10%	Residential Sales	-1.04%	-0.104
14	Real Gasoline Price (Lagged One Month)	-10%	Residential Sales	1.04%	-0.104
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

(1)
Model : Commercial Sales

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Commercial Customers	10%	Commercial Sales	10.00%	
2	Commercial Customers	-10%	Commercial Sales	-10.00%	
3	Heating Degree Hours	10%	Commercial Sales	0.06%	0.006
4	Heating Degree Hours	-10%	Commercial Sales	-0.06%	0.006
5	Cooling Degree Hours	10%	Commercial Sales	0.69%	0.069
6	Cooling Degree Hours	-10%	Commercial Sales	-0.69%	0.069
7	Cooling Degree Hours (Lagged One Month)	10%	Commercial Sales	0.60%	0.060
8	Cooling Degree Hours (Lagged One Month)	-10%	Commercial Sales	-0.60%	0.060
9	Florida Real per Capita Income	10%	Commercial Sales	1.51%	0.151
10	Florida Real per Capita Income	-10%	Commercial Sales	-1.51%	0.151
11	Inactive Ratio	10%	Commercial Sales	-0.77%	-0.077
12	Inactive Ratio	-10%	Commercial Sales	0.77%	-0.077
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

(1)
Model : Small Industrial Sales

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Small Industrial Customers	10%	Small Industrial Sales	10.00%	
2	Small Industrial Customers	-10%	Small Industrial Sales	-10.00%	
3	Heating Degree Hours	10%	Small Industrial Sales	0.19%	0.019
4	Heating Degree Hours	-10%	Small Industrial Sales	-0.19%	0.019
5	Cooling Degree Hours	10%	Small Industrial Sales	1.69%	0.169
6	Cooling Degree Hours	-10%	Small Industrial Sales	-1.69%	0.169
7	Florida Disposable Income	10%	Small Industrial Sales	5.89%	0.589
8	Florida Disposable Income	-10%	Small Industrial Sales	-5.89%	0.589
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

(1)
Model : Medium Industrial Sales

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Cooling Degree Hours	10%	Medium Industrial Sales	0.64%	0.064
2	Cooling Degree Hours	-10%	Medium Industrial Sales	-0.64%	0.064
3	Florida Disposable Income	10%	Medium Industrial Sales	10.11%	1.011
4	Florida Disposable Income	-10%	Medium Industrial Sales	-10.11%	1.011
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
X Projected Test Year Ended 12/31/13
___ Prior Year Ended ______
___ Historical Test Year Ended ______
Witness: Dr. Rosemary Morley

(1)
Model : Large Industrial Sales

Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)	(6) Elasticity
1	Real Industrial Price of Electricity	10%	Large Industrial Sales	-1.47%	-0.147
2	Real Industrial Price of Electricity	-10%	Large Industrial Sales	1.47%	-0.147
3	Florida Per Capita Income	10%	Large Industrial Sales	14.20%	1.420
4	Florida Per Capita Income	-10%	Large Industrial Sales	-14.20%	1.420
5	CPI	10%	Large Industrial Sales	-14.53%	-1.453
6	CPI	-10%	Large Industrial Sales	14.53%	-1.453
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended __/__/__
____ Historical Test Year Ended __/__/__
Witness: Dr. Rosemary Morley

Line No.	(1)
1	See attachments 1 through 13.

Supporting Schedules:

Recap Schedules:

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
1990	1	3,143,305	12,840,486	0
1990	2	3,156,536	12,873,014	0
1990	3	3,166,277	12,905,543	0
1990	4	3,162,286	12,938,071	0
1990	5	3,142,492	12,964,793	0
1990	6	3,138,589	12,991,515	0
1990	7	3,141,228	13,018,236	0
1990	8	3,145,324	13,044,958	0
1990	9	3,153,378	13,071,680	0
1990	10	3,162,736	13,098,402	0
1990	11	3,185,460	13,125,123	0
1990	12	3,208,196	13,151,845	0
1991	1	3,224,326	13,178,567	0
1991	2	3,234,722	13,205,289	0
1991	3	3,242,845	13,232,010	0
1991	4	3,233,172	13,258,732	0
1991	5	3,212,970	13,278,633	0
1991	6	3,207,144	13,298,534	0
1991	7	3,207,227	13,318,434	0
1991	8	3,210,321	13,338,335	0
1991	9	3,214,505	13,358,236	0
1991	10	3,222,678	13,378,137	0
1991	11	3,244,184	13,398,037	0
1991	12	3,263,370	13,417,938	0
1992	1	3,279,470	13,437,839	0
1992	2	3,290,137	13,457,740	0
1992	3	3,296,648	13,477,640	0
1992	4	3,288,200	13,497,541	0
1992	5	3,267,113	13,516,922	0
1992	6	3,262,067	13,536,303	0
1992	7	3,264,307	13,555,685	0
1992	8	3,268,605	13,575,066	0
1992	9	3,270,387	13,594,447	0
1992	10	3,274,980	13,613,828	0
1992	11	3,296,948	13,633,209	0
1992	12	3,315,995	13,652,590	0
1993	1	3,331,185	13,671,972	0
1993	2	3,343,984	13,691,353	0
1993	3	3,351,722	13,710,734	0
1993	4	3,347,726	13,730,115	0
1993	5	3,344,344	13,756,252	0
1993	6	3,333,683	13,782,389	0
1993	7	3,338,089	13,808,526	0
1993	8	3,346,275	13,834,662	0
1993	9	3,349,064	13,860,799	0
1993	10	3,354,219	13,886,936	0
1993	11	3,375,891	13,913,073	0
1993	12	3,393,118	13,939,210	0
1994	1	3,408,346	13,965,347	0
1994	2	3,419,751	13,991,483	0
1994	3	3,428,668	14,017,620	0
1994	4	3,426,781	14,043,757	0
1994	5	3,412,376	14,068,110	0

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
1994	6	3,405,058	14,092,463	0
1994	7	3,403,118	14,116,816	0
1994	8	3,412,225	14,141,169	0
1994	9	3,416,499	14,165,522	0
1994	10	3,423,149	14,189,875	0
1994	11	3,445,517	14,214,227	0
1994	12	3,464,752	14,238,580	0
1995	1	3,479,882	14,262,933	0
1995	2	3,489,886	14,287,286	0
1995	3	3,495,203	14,311,639	0
1995	4	3,489,830	14,335,992	0
1995	5	3,476,134	14,359,944	0
1995	6	3,474,401	14,383,897	0
1995	7	3,474,534	14,407,849	0
1995	8	3,477,674	14,431,802	0
1995	9	3,484,335	14,455,754	0
1995	10	3,491,443	14,479,707	0
1995	11	3,508,010	14,503,659	0
1995	12	3,524,220	14,527,611	0
1996	1	3,542,723	14,551,564	0
1996	2	3,549,253	14,575,516	0
1996	3	3,554,347	14,599,469	0
1996	4	3,554,535	14,623,421	0
1996	5	3,541,413	14,649,662	0
1996	6	3,537,834	14,675,903	0
1996	7	3,538,830	14,702,144	0
1996	8	3,542,393	14,728,385	0
1996	9	3,546,020	14,754,626	0
1996	10	3,551,534	14,780,868	0
1996	11	3,565,756	14,807,109	0
1996	12	3,584,330	14,833,350	0
1997	1	3,598,844	14,859,591	0
1997	2	3,608,998	14,885,832	0
1997	3	3,618,505	14,912,073	0
1997	4	3,616,878	14,938,314	0
1997	5	3,604,275	14,962,656	0
1997	6	3,600,262	14,986,999	0
1997	7	3,605,171	15,011,341	0
1997	8	3,609,958	15,035,683	0
1997	9	3,617,682	15,060,025	0
1997	10	3,622,133	15,084,368	0
1997	11	3,633,718	15,108,710	0
1997	12	3,649,397	15,133,052	0
1998	1	3,659,292	15,157,394	0
1998	2	3,670,765	15,181,737	0
1998	3	3,679,143	15,206,079	0
1998	4	3,681,090	15,230,421	0
1998	5	3,669,276	15,259,573	0
1998	6	3,670,638	15,288,725	0
1998	7	3,675,986	15,317,877	0
1998	8	3,678,422	15,347,029	0
1998	9	3,682,906	15,376,181	0
1998	10	3,686,366	15,405,333	0

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
1998	11	3,699,079	15,434,484	0
1998	12	3,712,676	15,463,636	0
1999	1	3,728,425	15,492,788	0
1999	2	3,739,166	15,521,940	0
1999	3	3,749,621	15,551,092	0
1999	4	3,750,775	15,580,244	0
1999	5	3,744,058	15,613,792	0
1999	6	3,744,561	15,647,341	0
1999	7	3,747,139	15,680,889	0
1999	8	3,754,576	15,714,437	0
1999	9	3,762,519	15,747,986	0
1999	10	3,769,162	15,781,534	0
1999	11	3,782,373	15,815,082	0
1999	12	3,799,737	15,848,631	0
2000	1	3,813,825	15,882,179	0
2000	2	3,827,374	15,915,727	0
2000	3	3,839,287	15,949,276	0
2000	4	3,844,046	15,982,824	0
2000	5	3,837,532	16,009,680	0
2000	6	3,838,927	16,036,537	0
2000	7	3,842,150	16,063,393	0
2000	8	3,850,200	16,090,249	0
2000	9	3,857,165	16,117,106	0
2000	10	3,864,218	16,143,962	0
2000	11	3,875,425	16,170,818	0
2000	12	3,890,055	16,197,675	0
2001	1	3,906,441	16,224,531	0
2001	2	3,917,697	16,251,387	0
2001	3	3,927,206	16,278,244	0
2001	4	3,933,081	16,305,100	0
2001	5	3,927,427	16,332,530	0
2001	6	3,925,818	16,359,959	0
2001	7	3,931,997	16,387,389	0
2001	8	3,938,314	16,414,819	0
2001	9	3,942,236	16,442,248	0
2001	10	3,947,996	16,469,678	0
2001	11	3,955,551	16,497,108	0
2001	12	3,969,611	16,524,537	0
2002	1	3,979,705	16,551,967	0
2002	2	3,993,899	16,579,397	0
2002	3	4,004,901	16,606,826	0
2002	4	4,012,387	16,634,256	0
2002	5	4,009,728	16,663,044	0
2002	6	4,011,076	16,691,831	0
2002	7	4,016,662	16,720,619	0
2002	8	4,025,172	16,749,406	0
2002	9	4,030,691	16,778,194	0
2002	10	4,038,763	16,806,981	0
2002	11	4,051,067	16,835,769	0
2002	12	4,063,603	16,864,556	0
2003	1	4,072,297	16,893,344	0
2003	2	4,086,234	16,922,131	0
2003	3	4,098,572	16,950,919	0

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
2003	4	4,106,996	16,979,706	0
2003	5	4,105,168	17,012,633	0
2003	6	4,109,068	17,045,559	0
2003	7	4,114,415	17,078,486	0
2003	8	4,121,357	17,111,412	0
2003	9	4,130,447	17,144,339	0
2003	10	4,140,703	17,177,265	0
2003	11	4,154,314	17,210,192	0
2003	12	4,167,077	17,243,118	0
2004	1	4,177,767	17,276,045	0
2004	2	4,191,930	17,308,971	0
2004	3	4,206,064	17,341,898	0
2004	4	4,216,720	17,374,824	0
2004	5	4,218,160	17,408,435	0
2004	6	4,224,545	17,442,046	0
2004	7	4,233,818	17,475,657	0
2004	8	4,242,328	17,509,268	0
2004	9	4,239,357	17,542,879	0
2004	10	4,234,493	17,576,490	0
2004	11	4,251,917	17,610,101	0
2004	12	4,257,011	17,643,712	0
2005	1	4,272,459	17,677,323	0
2005	2	4,287,988	17,710,934	0
2005	3	4,299,864	17,744,545	0
2005	4	4,310,180	17,778,156	0
2005	5	4,313,996	17,809,516	0
2005	6	4,320,906	17,840,876	0
2005	7	4,327,794	17,872,236	0
2005	8	4,340,306	17,903,596	0
2005	9	4,343,095	17,934,956	0
2005	10	4,344,668	17,966,316	0
2005	11	4,345,746	17,997,675	0
2005	12	4,355,740	18,029,035	0
2006	1	4,369,236	18,060,395	0
2006	2	4,377,958	18,091,755	0
2006	3	4,390,093	18,123,115	0
2006	4	4,398,215	18,154,475	0
2006	5	4,397,210	18,178,833	0
2006	6	4,403,628	18,203,191	0
2006	7	4,406,505	18,227,548	0
2006	8	4,416,127	18,251,906	0
2006	9	4,425,222	18,276,264	0
2006	10	4,429,977	18,300,622	0
2006	11	4,443,418	18,324,979	0
2006	12	4,457,161	18,349,337	0
2007	1	4,465,732	18,373,695	0
2007	2	4,476,835	18,398,053	0
2007	3	4,488,392	18,422,410	0
2007	4	4,493,310	18,446,768	0
2007	5	4,494,060	18,460,696	0
2007	6	4,497,400	18,474,624	0
2007	7	4,502,735	18,488,552	0
2007	8	4,508,215	18,502,480	0

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
2007	9	4,507,674	18,516,408	0
2007	10	4,507,737	18,530,337	0
2007	11	4,507,950	18,544,265	0
2007	12	4,509,032	18,558,193	0
2008	1	4,512,537	18,572,121	0
2008	2	4,519,123	18,586,049	0
2008	3	4,519,652	18,599,977	0
2008	4	4,518,324	18,613,905	0
2008	5	4,514,164	18,620,032	0
2008	6	4,514,262	18,626,158	0
2008	7	4,509,574	18,632,285	0
2008	8	4,507,318	18,638,412	0
2008	9	4,503,137	18,644,538	0
2008	10	4,501,918	18,650,665	0
2008	11	4,498,960	18,656,792	0
2008	12	4,497,793	18,662,918	0
2009	1	4,497,781	18,669,045	0
2009	2	4,502,684	18,675,172	0
2009	3	4,502,987	18,681,298	0
2009	4	4,502,465	18,687,425	0
2009	5	4,499,097	18,696,915	0
2009	6	4,497,918	18,706,406	0
2009	7	4,498,393	18,715,896	0
2009	8	4,498,960	18,725,387	0
2009	9	4,495,923	18,734,877	0
2009	10	4,495,215	18,744,368	0
2009	11	4,498,782	18,753,858	0
2009	12	4,498,596	18,763,348	0
2010	1	4,502,130	18,772,839	0
2010	2	4,510,659	18,782,329	0
2010	3	4,516,712	18,791,820	0
2010	4	4,520,229	18,801,310	0
2010	5	4,521,728	18,809,936	0
2010	6	4,521,918	18,818,561	0
2010	7	4,522,790	18,827,187	0
2010	8	4,526,766	18,835,813	0
2010	9	4,524,923	18,844,438	0
2010	10	4,524,001	18,853,064	0
2010	11	4,525,048	18,861,690	0
2010	12	4,527,028	18,870,315	0
2011	1	4,533,029	18,878,941	0
2011	2	4,539,389	18,887,567	0
2011	3	4,546,574	18,896,192	0
2011	4	4,550,254	18,904,818	0
2011	5	4,549,811	18,913,526	0
2011	6	4,549,338	18,922,234	0
2011	7	4,549,687	18,930,942	0
2011	8	4,550,328	18,939,650	0
2011	9	4,551,337	18,948,358	-1,999
2011	10	4,551,086	18,957,066	-1,999
2011	11	4,552,446	18,965,774	-1,999
2011	12	4,554,567	18,974,482	-2,000
2012	1	4,559,979	18,983,190	-2,003

INPUTS FOR THE TOTAL CUSTOMER FORECAST

Year	Month	Total Customer	Florida Population	Out-of-Model Intercept Adjustment
2012	2	4,565,683	18,991,898	-2,005
2012	3	4,572,061	19,000,606	-2,008
2012	4	4,575,564	19,009,314	-2,009
2012	5	4,576,771	19,022,315	-2,010
2012	6	4,577,952	19,035,317	-2,011
2012	7	4,580,526	19,048,318	-2,012
2012	8	4,585,179	19,061,319	-2,014
2012	9	4,585,919	19,074,320	-2,014
2012	10	4,587,273	19,087,322	-2,015
2012	11	4,589,945	19,100,323	-2,016
2012	12	4,593,240	19,113,324	-2,017
2013	1	4,599,230	19,126,325	-2,020
2013	2	4,605,458	19,139,327	-2,023
2013	3	4,612,236	19,152,328	-2,026
2013	4	4,616,656	19,165,329	-2,028
2013	5	4,619,752	19,184,025	-2,029
2013	6	4,622,825	19,202,721	-2,030
2013	7	4,627,037	19,221,417	-2,032
2013	8	4,632,954	19,240,113	-2,035
2013	9	4,635,661	19,258,809	-2,036
2013	10	4,638,869	19,277,506	-2,037
2013	11	4,643,157	19,296,202	-2,039
2013	12	4,647,954	19,314,898	-2,041

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Total Customers	Calendar Heating Degree Days (Base - 45)	Calendar Winter Heating Degree Days (Base 66)	Calendar Cooling Degree Hours (Base - 72)	Inactive Ratio	Weather Sensitive Energy Efficiency Standards per Customer
2001	7	9,562,389	3,931,997	0.00	0.00	281.65	5.19%	0.00
2001	8	10,155,588	3,938,314	0.00	0.00	323.90	5.17%	0.00
2001	9	8,848,883	3,942,236	0.00	0.00	215.63	5.19%	0.00
2001	10	8,430,258	3,947,996	0.00	0.00	170.12	5.17%	0.00
2001	11	7,043,087	3,955,551	0.00	0.00	65.92	5.02%	0.00
2001	12	7,545,737	3,969,611	0.00	30.21	58.78	4.28%	0.00
2002	1	7,760,946	3,979,705	0.00	93.12	38.72	4.67%	0.00
2002	2	6,503,901	3,993,899	0.00	44.60	19.45	4.56%	0.00
2002	3	7,990,149	4,004,901	0.00	12.59	92.45	4.50%	0.00
2002	4	8,476,283	4,012,387	0.00	0.00	146.80	4.73%	0.00
2002	5	9,406,970	4,009,728	0.00	0.00	224.05	4.93%	0.00
2002	6	9,036,572	4,011,076	0.00	0.00	222.22	5.02%	0.00
2002	7	10,071,087	4,016,662	0.00	0.00	299.66	5.11%	0.00
2002	8	10,320,346	4,025,172	0.00	0.00	312.57	5.10%	0.00
2002	9	10,060,592	4,030,691	0.00	0.00	306.50	5.09%	0.00
2002	10	9,901,403	4,038,763	0.00	0.00	245.00	5.02%	0.00
2002	11	7,553,628	4,051,067	0.00	0.00	78.28	4.82%	0.00
2002	12	7,575,325	4,063,603	0.00	74.82	31.42	4.74%	0.00
2003	1	8,196,046	4,072,297	1.43	215.46	5.68	4.65%	0.00
2003	2	6,951,237	4,086,234	0.00	26.92	42.27	4.55%	0.00
2003	3	8,869,654	4,098,572	0.00	9.46	123.98	4.55%	0.00
2003	4	8,063,515	4,106,996	0.00	0.00	101.75	4.76%	0.00
2003	5	9,977,015	4,105,168	0.00	0.00	243.56	4.87%	0.00
2003	6	9,788,214	4,109,068	0.00	0.00	257.17	4.94%	0.00
2003	7	10,773,171	4,114,415	0.00	0.00	328.34	4.95%	0.00
2003	8	10,252,765	4,121,357	0.00	0.00	293.63	5.00%	0.00
2003	9	9,900,915	4,130,447	0.00	0.00	261.28	4.96%	0.00
2003	10	9,568,487	4,140,703	0.00	0.00	222.19	4.80%	0.00
2003	11	8,204,690	4,154,314	0.00	0.00	112.80	4.57%	0.00
2003	12	7,668,752	4,167,077	0.00	98.85	18.28	4.51%	0.00
2004	1	7,673,433	4,177,767	0.00	113.45	15.80	4.35%	0.00
2004	2	7,341,137	4,191,930	0.00	53.09	31.73	4.19%	0.00
2004	3	7,858,341	4,206,064	0.00	10.51	51.52	4.17%	0.00
2004	4	7,922,081	4,216,720	0.00	0.00	77.47	4.34%	0.00
2004	5	9,576,175	4,218,160	0.00	0.00	160.56	4.49%	0.00
2004	6	10,673,643	4,224,545	0.00	0.00	309.18	4.52%	0.00
2004	7	10,937,914	4,233,818	0.00	0.00	317.88	4.49%	0.00
2004	8	10,700,436	4,242,328	0.00	0.00	306.53	4.44%	0.00
2004	9	9,621,164	4,239,357	0.00	0.00	280.11	4.62%	0.00
2004	10	9,570,087	4,234,493	0.00	0.00	177.95	5.08%	0.00
2004	11	8,129,488	4,251,917	0.00	0.00	78.64	4.79%	0.00
2004	12	8,118,031	4,257,011	0.00	85.45	25.90	4.86%	0.00
2005	1	8,045,152	4,272,459	0.00	94.89	23.47	4.56%	0.00
2005	2	7,099,617	4,287,988	0.00	51.90	18.74	4.39%	0.00
2005	3	8,340,298	4,299,864	0.00	57.74	59.82	4.43%	0.00
2005	4	8,001,649	4,310,180	0.00	0.00	68.09	4.56%	0.00
2005	5	9,672,947	4,313,996	0.00	0.00	168.41	4.60%	0.00
2005	6	10,062,236	4,320,906	0.00	0.00	237.58	4.67%	0.00

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Total Customers	Calendar Heating Degree Days (Base - 45)	Calendar Winter Heating Degree Days (Base 66)	Calendar Cooling Degree Hours (Base - 72)	Inactive Ratio	Weather Sensitive Energy Efficiency Standards per Customer
2005	7	11,950,858	4,327,794	0.00	0.00	364.86	4.70%	0.00
2005	8	11,930,141	4,340,306	0.00	0.00	365.73	4.65%	0.00
2005	9	10,884,625	4,343,095	0.00	0.00	295.85	4.74%	0.00
2005	10	9,187,793	4,344,668	0.00	0.00	202.34	4.84%	0.00
2005	11	8,250,008	4,345,746	0.00	0.00	83.15	4.76%	0.00
2005	12	8,017,565	4,355,740	0.00	75.07	19.12	4.86%	0.00
2006	1	8,085,609	4,369,236	0.00	72.25	28.79	5.01%	0.00
2006	2	7,497,292	4,377,958	0.00	96.75	21.45	4.87%	0.00
2006	3	8,289,372	4,390,093	0.00	20.10	53.93	4.87%	0.00
2006	4	9,064,955	4,398,215	0.00	0.00	129.36	5.07%	0.01
2006	5	10,030,370	4,397,210	0.00	0.00	196.51	5.13%	0.01
2006	6	10,714,052	4,403,628	0.00	0.00	277.03	5.23%	0.02
2006	7	11,095,797	4,406,505	0.00	0.00	300.36	5.30%	0.02
2006	8	11,564,017	4,416,127	0.00	0.00	324.00	5.24%	0.02
2006	9	10,520,313	4,425,222	0.00	0.00	267.90	5.23%	0.02
2006	10	9,930,813	4,429,977	0.00	0.00	196.84	5.24%	0.01
2006	11	8,136,377	4,443,418	0.00	0.00	67.05	5.06%	0.01
2006	12	8,477,014	4,457,161	0.00	13.45	63.60	4.97%	0.00
2007	1	8,469,671	4,465,732	0.00	47.23	45.65	4.93%	0.00
2007	2	7,527,571	4,476,835	0.00	74.90	30.40	4.79%	0.00
2007	3	8,435,515	4,488,392	0.00	11.52	62.90	4.70%	0.01
2007	4	8,579,552	4,493,310	0.00	0.00	101.96	4.87%	0.01
2007	5	9,663,511	4,494,060	0.00	0.00	167.19	4.97%	0.02
2007	6	10,343,275	4,497,400	0.00	0.00	252.06	5.05%	0.03
2007	7	11,373,076	4,502,735	0.00	0.00	317.69	5.05%	0.03
2007	8	12,110,271	4,508,215	0.00	0.00	364.00	5.13%	0.03
2007	9	10,759,822	4,507,674	0.00	0.00	282.71	5.22%	0.03
2007	10	10,632,392	4,507,737	0.00	0.00	252.26	5.28%	0.02
2007	11	8,074,326	4,507,950	0.00	0.00	75.00	5.38%	0.01
2007	12	8,563,233	4,509,032	0.00	15.36	77.07	5.42%	0.00
2008	1	8,158,564	4,512,537	0.00	64.96	29.21	5.44%	0.00
2008	2	7,896,972	4,519,123	0.00	21.53	59.29	5.40%	0.00
2008	3	8,325,921	4,519,652	0.00	9.31	65.69	5.53%	0.01
2008	4	8,619,990	4,518,324	0.00	0.00	109.06	5.77%	0.02
2008	5	10,292,599	4,514,164	0.00	0.00	237.13	5.89%	0.03
2008	6	10,508,760	4,514,262	0.00	0.00	279.15	6.05%	0.04
2008	7	10,745,283	4,509,574	0.00	0.00	286.60	6.17%	0.04
2008	8	11,090,020	4,507,318	0.00	0.00	325.17	6.30%	0.05
2008	9	10,640,369	4,503,137	0.00	0.00	294.55	6.40%	0.04
2008	10	9,367,637	4,501,918	0.00	0.00	173.31	6.53%	0.03
2008	11	7,648,144	4,498,960	0.00	0.00	54.14	6.58%	0.01
2008	12	7,806,098	4,497,793	0.00	24.94	37.60	6.70%	0.01
2009	1	8,007,278	4,497,781	0.00	108.69	22.67	6.64%	0.00
2009	2	7,235,663	4,502,684	0.00	80.10	19.41	6.62%	0.01
2009	3	8,009,351	4,502,987	0.00	29.31	58.11	6.68%	0.01
2009	4	8,493,145	4,502,465	0.00	0.00	123.07	6.79%	0.02
2009	5	9,656,281	4,499,097	0.00	0.00	205.56	6.84%	0.03
2009	6	10,367,469	4,497,918	0.00	0.00	286.29	6.96%	0.05

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Total Customers	Calendar Heating Degree Days (Base - 45)	Calendar Winter Heating Degree Days (Base 66)	Calendar Cooling Degree Hours (Base - 72)	Inactive Ratio	Weather Sensitive Energy Efficiency Standards per Customer
2009	7	11,007,925	4,498,393	0.00	0.00	333.19	6.97%	0.05
2009	8	11,448,322	4,498,960	0.00	0.00	358.91	7.00%	0.06
2009	9	10,342,759	4,495,923	0.00	0.00	293.29	7.06%	0.05
2009	10	10,338,743	4,495,215	0.00	0.00	264.37	7.05%	0.03
2009	11	8,115,012	4,498,782	0.00	0.00	100.31	6.93%	0.02
2009	12	8,215,468	4,498,596	0.00	48.45	63.29	6.94%	0.01
2010	1	9,390,504	4,502,130	8.09	244.21	19.03	6.77%	0.01
2010	2	7,653,971	4,510,659	0.00	178.08	7.17	6.65%	0.01
2010	3	7,879,752	4,516,712	0.00	93.98	15.39	6.59%	0.01
2010	4	8,037,871	4,520,229	0.00	0.00	89.08	6.61%	0.02
2010	5	10,395,115	4,521,728	0.00	0.00	255.20	6.61%	0.04
2010	6	11,409,507	4,521,918	0.00	0.00	357.45	6.63%	0.06
2010	7	11,649,520	4,522,790	0.00	0.00	367.30	6.61%	0.07
2010	8	11,521,499	4,526,766	0.00	0.00	354.65	6.59%	0.07
2010	9	10,666,454	4,524,923	0.00	0.00	310.21	6.64%	0.06
2010	10	9,299,921	4,524,001	0.00	0.00	181.65	6.64%	0.04
2010	11	7,811,927	4,525,048	0.00	0.00	78.04	6.59%	0.02
2010	12	8,885,262	4,527,028	2.58	258.63	3.75	6.49%	0.01
2011	1	7,922,768	4,533,028	0.00	112.82	13.49	6.42%	0.01
2011	2	7,253,717	4,539,388	0.00	34.56	42.23	6.32%	0.01
2011	3	8,196,117	4,546,573	0.00	11.43	79.01	6.20%	0.01
2011	4	9,460,285	4,550,253	0.00	0.00	190.37	6.20%	0.03
2011	5	10,098,308	4,549,810	0.00	0.00	242.31	6.21%	0.05
2011	6	10,539,641	4,549,337	0.00	0.00	304.56	6.27%	0.07
2011	7	11,211,614	4,549,686	0.00	0.00	355.81	6.27%	0.08
2011	8	11,034,851	4,550,328	0.00	0.00	325.15	6.29%	0.08
2011	9	10,233,834	4,551,337	0.00	0.00	278.07	6.28%	0.07
2011	10	9,596,433	4,551,086	0.00	0.00	196.85	6.28%	0.05
2011	11	7,985,879	4,552,446	0.00	0.00	80.95	6.24%	0.02
2011	12	8,201,493	4,554,567	0.18	69.31	39.28	6.14%	0.01
2012	1	8,281,180	4,559,979	0.48	106.56	25.24	6.10%	0.01
2012	2	7,411,022	4,565,683	0.00	60.63	32.29	6.02%	0.01
2012	3	8,307,816	4,572,061	0.00	28.10	64.68	5.93%	0.02
2012	4	8,483,674	4,575,564	0.00	0.00	109.60	5.94%	0.03
2012	5	9,791,945	4,576,771	0.00	0.00	207.71	5.92%	0.06
2012	6	10,204,539	4,577,952	0.00	0.00	272.38	5.96%	0.08
2012	7	11,110,969	4,580,526	0.00	0.00	326.06	5.92%	0.09
2012	8	11,088,953	4,585,179	0.00	0.00	325.15	5.87%	0.10
2012	9	10,281,836	4,585,919	0.00	0.00	278.07	5.89%	0.09
2012	10	9,662,478	4,587,273	0.00	0.00	196.85	5.87%	0.06
2012	11	8,079,384	4,589,945	0.00	0.00	80.95	5.81%	0.03
2012	12	8,317,094	4,593,240	0.18	69.31	39.28	5.71%	0.01
2013	1	8,409,042	4,599,230	0.48	106.56	25.24	5.67%	0.01
2013	2	7,528,345	4,605,458	0.00	60.63	32.29	5.60%	0.01
2013	3	8,419,646	4,612,236	0.00	28.10	64.68	5.51%	0.02
2013	4	8,574,008	4,616,656	0.00	0.00	109.60	5.52%	0.04
2013	5	9,875,896	4,619,752	0.00	0.00	207.71	5.47%	0.06
2013	6	10,252,553	4,622,825	0.00	0.00	272.38	5.48%	0.09

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Total Customers	Calendar Heating Degree Days (Base - 45)	Calendar Winter Heating Degree Days (Base 66)	Calendar Cooling Degree Hours (Base - 72)	Inactive Ratio	Weather Sensitive Energy Efficiency Standards per Customer
2013	7	11,166,638	4,627,037	0.00	0.00	326.06	5.42%	0.10
2013	8	11,144,392	4,632,954	0.00	0.00	325.15	5.36%	0.11
2013	9	10,352,920	4,635,661	0.00	0.00	278.07	5.35%	0.10
2013	10	9,768,715	4,638,869	0.00	0.00	196.85	5.30%	0.07
2013	11	8,220,324	4,643,157	0.00	0.00	80.95	5.22%	0.03
2013	12	8,488,045	4,647,954	0.18	69.31	39.28	5.11%	0.01

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Dummy March 2003	Dummy February	Dummy April	Dummy June	Dummy September	Dummy May 2004
2001	7	9,562,389	14.21	0	0	0	0	0	0
2001	8	10,155,588	14.16	0	0	0	0	0	0
2001	9	8,848,883	14.11	0	0	0	0	1	0
2001	10	8,430,258	14.01	0	0	0	0	0	0
2001	11	7,043,087	14.04	0	0	0	0	0	0
2001	12	7,545,737	14.09	0	0	0	0	0	0
2002	1	7,760,946	14.19	0	0	0	0	0	0
2002	2	6,503,901	14.17	0	1	0	0	0	0
2002	3	7,990,149	14.13	0	0	0	0	0	0
2002	4	8,476,283	14.09	0	0	1	0	0	0
2002	5	9,406,970	14.05	0	0	0	0	0	0
2002	6	9,036,572	14.02	0	0	0	1	0	0
2002	7	10,071,087	13.96	0	0	0	0	0	0
2002	8	10,320,346	13.97	0	0	0	0	0	0
2002	9	10,060,592	13.99	0	0	0	0	1	0
2002	10	9,901,403	14.03	0	0	0	0	0	0
2002	11	7,553,628	13.99	0	0	0	0	0	0
2002	12	7,575,325	13.94	0	0	0	0	0	0
2003	1	8,196,046	13.85	0	0	0	0	0	0
2003	2	6,951,237	13.84	0	1	0	0	0	0
2003	3	8,869,654	13.87	1	0	0	0	0	0
2003	4	8,063,515	13.88	0	0	1	0	0	0
2003	5	9,977,015	13.90	0	0	0	0	0	0
2003	6	9,788,214	13.91	0	0	0	1	0	0
2003	7	10,773,171	13.89	0	0	0	0	0	0
2003	8	10,252,765	13.94	0	0	0	0	0	0
2003	9	9,900,915	14.00	0	0	0	0	1	0
2003	10	9,568,487	14.05	0	0	0	0	0	0
2003	11	8,204,690	14.13	0	0	0	0	0	0
2003	12	7,668,752	14.21	0	0	0	0	0	0
2004	1	7,673,433	14.28	0	0	0	0	0	0
2004	2	7,341,137	14.38	0	1	0	0	0	0
2004	3	7,858,341	14.48	0	0	0	0	0	0
2004	4	7,922,081	14.61	0	0	1	0	0	0
2004	5	9,576,175	14.66	0	0	0	0	0	1
2004	6	10,673,643	14.70	0	0	0	1	0	0
2004	7	10,937,914	14.72	0	0	0	0	0	0
2004	8	10,700,436	14.81	0	0	0	0	0	0
2004	9	9,621,164	14.90	0	0	0	0	1	0
2004	10	9,570,087	15.02	0	0	0	0	0	0
2004	11	8,129,488	15.08	0	0	0	0	0	0
2004	12	8,118,031	15.11	0	0	0	0	0	0
2005	1	8,045,152	15.15	0	0	0	0	0	0
2005	2	7,099,617	15.19	0	1	0	0	0	0
2005	3	8,340,298	15.25	0	0	0	0	0	0
2005	4	8,001,649	15.29	0	0	1	0	0	0
2005	5	9,672,947	15.38	0	0	0	0	0	0
2005	6	10,062,236	15.45	0	0	0	1	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Dummy March 2003	Dummy February	Dummy April	Dummy June	Dummy September	Dummy May 2004
2005	7	11,950,858	15.57	0	0	0	0	0	0
2005	8	11,930,141	15.58	0	0	0	0	0	0
2005	9	10,884,625	15.58	0	0	0	0	1	0
2005	10	9,187,793	15.51	0	0	0	0	0	0
2005	11	8,250,008	15.62	0	0	0	0	0	0
2005	12	8,017,565	15.78	0	0	0	0	0	0
2006	1	8,085,609	15.98	0	0	0	0	0	0
2006	2	7,497,292	16.06	0	1	0	0	0	0
2006	3	8,289,372	16.11	0	0	0	0	0	0
2006	4	9,064,955	16.19	0	0	1	0	0	0
2006	5	10,030,370	16.20	0	0	0	0	0	0
2006	6	10,714,052	16.22	0	0	0	1	0	0
2006	7	11,095,797	16.22	0	0	0	0	0	0
2006	8	11,564,017	16.25	0	0	0	0	0	0
2006	9	10,520,313	16.29	0	0	0	0	1	0
2006	10	9,930,813	16.34	0	0	0	0	0	0
2006	11	8,136,377	16.34	0	0	0	0	0	0
2006	12	8,477,014	16.33	0	0	0	0	0	0
2007	1	8,469,671	16.34	0	0	0	0	0	0
2007	2	7,527,571	16.30	0	1	0	0	0	0
2007	3	8,435,515	16.25	0	0	0	0	0	0
2007	4	8,579,552	16.20	0	0	1	0	0	0
2007	5	9,663,511	16.16	0	0	0	0	0	0
2007	6	10,343,275	16.13	0	0	0	1	0	0
2007	7	11,373,076	16.10	0	0	0	0	0	0
2007	8	12,110,271	16.05	0	0	0	0	0	0
2007	9	10,759,822	15.99	0	0	0	0	1	0
2007	10	10,632,392	15.95	0	0	0	0	0	0
2007	11	8,074,326	15.87	0	0	0	0	0	0
2007	12	8,563,233	15.79	0	0	0	0	0	0
2008	1	8,158,564	15.71	0	0	0	0	0	0
2008	2	7,896,972	15.65	0	1	0	0	0	0
2008	3	8,325,921	15.57	0	0	0	0	0	0
2008	4	8,619,990	15.56	0	0	1	0	0	0
2008	5	10,292,599	15.40	0	0	0	0	0	0
2008	6	10,508,760	15.23	0	0	0	1	0	0
2008	7	10,745,283	14.99	0	0	0	0	0	0
2008	8	11,090,020	14.91	0	0	0	0	0	0
2008	9	10,640,369	14.85	0	0	0	0	1	0
2008	10	9,367,637	14.87	0	0	0	0	0	0
2008	11	7,648,144	14.69	0	0	0	0	0	0
2008	12	7,806,098	14.47	0	0	0	0	0	0
2009	1	8,007,278	14.19	0	0	0	0	0	0
2009	2	7,235,663	14.08	0	1	0	0	0	0
2009	3	8,009,351	14.02	0	0	0	0	0	0
2009	4	8,493,145	13.98	0	0	1	0	0	0
2009	5	9,656,281	13.86	0	0	0	0	0	0
2009	6	10,367,469	13.72	0	0	0	1	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Dummy March 2003	Dummy February	Dummy April	Dummy June	Dummy September	Dummy May 2004
2009	7	11,007,925	13.53	0	0	0	0	0	0
2009	8	11,448,322	13.46	0	0	0	0	0	0
2009	9	10,342,759	13.43	0	0	0	0	1	0
2009	10	10,338,743	13.37	0	0	0	0	0	0
2009	11	8,115,012	13.34	0	0	0	0	0	0
2009	12	8,215,468	13.32	0	0	0	0	0	0
2010	1	9,390,504	13.24	0	0	0	0	0	0
2010	2	7,653,971	13.30	0	1	0	0	0	0
2010	3	7,879,752	13.38	0	0	0	0	0	0
2010	4	8,037,871	13.50	0	0	1	0	0	0
2010	5	10,395,115	13.51	0	0	0	0	0	0
2010	6	11,409,507	13.48	0	0	0	1	0	0
2010	7	11,649,520	13.45	0	0	0	0	0	0
2010	8	11,521,499	13.44	0	0	0	0	0	0
2010	9	10,666,454	13.44	0	0	0	0	1	0
2010	10	9,299,921	13.42	0	0	0	0	0	0
2010	11	7,811,927	13.43	0	0	0	0	0	0
2010	12	8,885,262	13.44	0	0	0	0	0	0
2011	1	7,922,768	13.44	0	0	0	0	0	0
2011	2	7,253,717	13.48	0	1	0	0	0	0
2011	3	8,196,117	13.52	0	0	0	0	0	0
2011	4	9,460,285	13.56	0	0	1	0	0	0
2011	5	10,098,308	13.59	0	0	0	0	0	0
2011	6	10,539,641	13.62	0	0	0	1	0	0
2011	7	11,211,614	13.65	0	0	0	0	0	0
2011	8	11,034,851	13.69	0	0	0	0	0	0
2011	9	10,233,834	13.72	0	0	0	0	1	0
2011	10	9,596,433	13.78	0	0	0	0	0	0
2011	11	7,985,879	13.79	0	0	0	0	0	0
2011	12	8,201,493	13.79	0	0	0	0	0	0
2012	1	8,281,180	13.77	0	0	0	0	0	0
2012	2	7,411,022	13.79	0	1	0	0	0	0
2012	3	8,307,816	13.83	0	0	0	0	0	0
2012	4	8,483,674	13.86	0	0	1	0	0	0
2012	5	9,791,945	13.89	0	0	0	0	0	0
2012	6	10,204,539	13.92	0	0	0	1	0	0
2012	7	11,110,969	13.94	0	0	0	0	0	0
2012	8	11,088,953	13.97	0	0	0	0	0	0
2012	9	10,281,836	14.00	0	0	0	0	1	0
2012	10	9,662,478	14.04	0	0	0	0	0	0
2012	11	8,079,384	14.05	0	0	0	0	0	0
2012	12	8,317,094	14.07	0	0	0	0	0	0
2013	1	8,409,042	14.07	0	0	0	0	0	0
2013	2	7,528,345	14.11	0	1	0	0	0	0
2013	3	8,419,646	14.15	0	0	0	0	0	0
2013	4	8,574,008	14.18	0	0	1	0	0	0
2013	5	9,875,896	14.22	0	0	0	0	0	0
2013	6	10,252,553	14.26	0	0	0	1	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Dummy March 2003	Dummy February	Dummy April	Dummy June	Dummy September	Dummy May 2004
2013	7	11,166,638	14.30	0	0	0	0	0	0
2013	8	11,144,392	14.33	0	0	0	0	0	0
2013	9	10,352,920	14.35	0	0	0	0	1	0
2013	10	9,768,715	14.36	0	0	0	0	0	0
2013	11	8,220,324	14.42	0	0	0	0	0	0
2013	12	8,488,045	14.48	0	0	0	0	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Dummy November	Dummy November 2005	CPI for Energy (1982 - 84=100)	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for Smart Meters	Out-of-Model Adjustment for New/Modified Wholesale Contracts
2001	7	9,562,389	0	0	133.20	0	0	0
2001	8	10,155,588	0	0	129.30	0	0	0
2001	9	8,848,883	0	0	125.29	0	0	0
2001	10	8,430,258	0	0	119.77	0	0	0
2001	11	7,043,087	1	0	117.45	0	0	0
2001	12	7,545,737	0	0	116.48	0	0	0
2002	1	7,760,946	0	0	113.01	0	0	0
2002	2	6,503,901	0	0	114.89	0	0	0
2002	3	7,990,149	0	0	117.40	0	0	0
2002	4	8,476,283	0	0	120.79	0	0	0
2002	5	9,406,970	0	0	121.94	0	0	0
2002	6	9,036,572	0	0	122.26	0	0	0
2002	7	10,071,087	0	0	122.70	0	0	0
2002	8	10,320,346	0	0	122.76	0	0	0
2002	9	10,060,592	0	0	123.74	0	0	0
2002	10	9,901,403	0	0	121.95	0	0	0
2002	11	7,553,628	1	0	126.86	0	0	0
2002	12	7,575,325	0	0	131.88	0	0	0
2003	1	8,196,046	0	0	141.58	0	0	0
2003	2	6,951,237	0	0	140.06	0	0	0
2003	3	8,869,654	0	0	136.55	0	0	0
2003	4	8,063,515	0	0	130.53	0	0	0
2003	5	9,977,015	0	0	131.27	0	0	0
2003	6	9,788,214	0	0	133.91	0	0	0
2003	7	10,773,171	0	0	137.45	0	0	0
2003	8	10,252,765	0	0	137.95	0	0	0
2003	9	9,900,915	0	0	137.51	0	0	0
2003	10	9,568,487	0	0	135.72	0	0	0
2003	11	8,204,690	1	0	137.52	0	0	0
2003	12	7,668,752	0	0	140.27	0	0	0
2004	1	7,673,433	0	0	143.72	0	0	0
2004	2	7,341,137	0	0	145.20	0	0	0
2004	3	7,858,341	0	0	145.87	0	0	0
2004	4	7,922,081	0	0	146.61	0	0	0
2004	5	9,576,175	0	0	147.28	0	0	0
2004	6	10,673,643	0	0	148.61	0	0	0
2004	7	10,937,914	0	0	148.33	0	0	0
2004	8	10,700,436	0	0	151.77	0	0	0
2004	9	9,621,164	0	0	155.40	0	0	0
2004	10	9,570,087	0	0	161.17	0	0	0
2004	11	8,129,488	1	0	162.02	0	0	0
2004	12	8,118,031	0	0	161.51	0	0	0
2005	1	8,045,152	0	0	161.06	0	0	0
2005	2	7,099,617	0	0	160.32	0	0	0
2005	3	8,340,298	0	0	161.12	0	0	0
2005	4	8,001,649	0	0	156.84	0	0	0
2005	5	9,672,947	0	0	164.05	0	0	0
2005	6	10,062,236	0	0	172.80	0	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Dummy November	Dummy November 2005	CPI for Energy (1982 - 84=100)	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for Smart Meters	Out-of-Model Adjustment for New/Modified Wholesale Contracts
2005	7	11,950,858	0	0	184.55	0	0	0
2005	8	11,930,141	0	0	189.05	0	0	0
2005	9	10,884,625	0	0	190.90	0	0	0
2005	10	9,187,793	0	0	195.11	0	0	0
2005	11	8,250,008	1	1	194.86	0	0	0
2005	12	8,017,565	0	0	194.53	0	0	0
2006	1	8,085,609	0	0	193.28	0	0	0
2006	2	7,497,292	0	0	193.91	0	0	0
2006	3	8,289,372	0	0	195.51	0	0	0
2006	4	9,064,955	0	0	195.66	0	0	0
2006	5	10,030,370	0	0	199.69	0	0	0
2006	6	10,714,052	0	0	202.75	0	0	0
2006	7	11,095,797	0	0	212.22	0	0	0
2006	8	11,564,017	0	0	206.68	0	0	0
2006	9	10,520,313	0	0	199.01	0	0	0
2006	10	9,930,813	0	0	186.52	0	0	0
2006	11	8,136,377	1	0	185.64	0	0	0
2006	12	8,477,014	0	0	188.74	0	0	0
2007	1	8,469,671	0	0	189.13	0	0	0
2007	2	7,527,571	0	0	194.63	0	0	0
2007	3	8,435,515	0	0	199.31	0	0	0
2007	4	8,579,552	0	0	207.11	0	0	0
2007	5	9,663,511	0	0	207.76	0	0	0
2007	6	10,343,275	0	0	207.50	0	0	0
2007	7	11,373,076	0	0	205.12	0	0	0
2007	8	12,110,271	0	0	208.00	0	0	0
2007	9	10,759,822	0	0	212.37	0	0	0
2007	10	10,632,392	0	0	216.68	0	0	0
2007	11	8,074,326	1	0	220.56	0	0	0
2007	12	8,563,233	0	0	223.84	0	0	0
2008	1	8,158,564	0	0	226.65	0	0	0
2008	2	7,896,972	0	0	230.06	0	0	0
2008	3	8,325,921	0	0	235.07	0	0	0
2008	4	8,619,990	0	0	236.97	0	0	0
2008	5	10,292,599	0	0	247.92	0	0	0
2008	6	10,508,760	0	0	256.11	0	0	0
2008	7	10,745,283	0	0	283.01	0	0	0
2008	8	11,090,020	0	0	266.97	0	0	0
2008	9	10,640,369	0	0	243.24	0	0	0
2008	10	9,367,637	0	0	213.28	0	0	0
2008	11	7,648,144	1	0	200.05	0	0	0
2008	12	7,806,098	0	0	194.31	0	0	0
2009	1	8,007,278	0	0	182.03	0	0	0
2009	2	7,235,663	0	0	181.42	0	0	0
2009	3	8,009,351	0	0	181.98	0	0	0
2009	4	8,493,145	0	0	179.18	0	0	0
2009	5	9,656,281	0	0	183.91	0	0	0
2009	6	10,367,469	0	0	189.63	0	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Dummy November	Dummy November 2005	CPI for Energy (1982 - 84=100)	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for Smart Meters	Out-of-Model Adjustment for New/Modified Wholesale Contracts
2009	7	11,007,925	0	0	196.92	0	0	0
2009	8	11,448,322	0	0	200.12	0	0	0
2009	9	10,342,759	0	0	202.18	0	0	0
2009	10	10,338,743	0	0	204.28	0	0	0
2009	11	8,115,012	1	0	207.21	0	0	0
2009	12	8,215,468	0	0	209.85	0	0	0
2010	1	9,390,504	0	0	215.89	0	0	0
2010	2	7,653,971	0	0	214.00	0	0	0
2010	3	7,879,752	0	0	210.72	0	0	0
2010	4	8,037,871	0	0	205.69	0	0	0
2010	5	10,395,115	0	0	205.04	0	0	0
2010	6	11,409,507	0	0	206.18	0	0	0
2010	7	11,649,520	0	0	205.33	0	0	0
2010	8	11,521,499	0	0	208.11	0	0	0
2010	9	10,666,454	0	0	211.63	0	0	0
2010	10	9,299,921	0	0	213.19	0	0	0
2010	11	7,811,927	1	0	219.12	0	0	0
2010	12	8,885,262	0	0	225.61	0	0	0
2011	1	7,922,768	0	0	233.37	0	0	0
2011	2	7,253,717	0	0	238.28	0	0	0
2011	3	8,196,117	0	0	241.82	0	0	0
2011	4	9,460,285	0	0	248.06	0	0	0
2011	5	10,098,308	0	0	248.78	0	0	0
2011	6	10,539,641	0	0	248.33	0	0	0
2011	7	11,211,614	0	0	249.18	0	0	0
2011	8	11,034,851	0	0	247.29	0	0	142,436
2011	9	10,233,834	0	0	245.49	0	0	129,237
2011	10	9,596,433	0	0	242.22	0	0	130,358
2011	11	7,985,879	1	0	242.43	0	0	97,900
2011	12	8,201,493	0	0	243.22	0	0	98,046
2012	1	8,281,180	0	0	244.64	0	0	112,574
2012	2	7,411,022	0	0	244.18	0	0	97,502
2012	3	8,307,816	0	0	243.46	0	0	112,866
2012	4	8,483,674	0	0	241.24	0	0	123,691
2012	5	9,791,945	0	0	242.63	0	0	134,604
2012	6	10,204,539	0	0	244.87	0	0	138,965
2012	7	11,110,969	0	0	247.40	0	0	148,866
2012	8	11,088,953	0	0	248.94	0	0	154,591
2012	9	10,281,836	0	0	249.93	0	0	140,675
2012	10	9,662,478	0	0	251.27	0	0	135,447
2012	11	8,079,384	1	0	252.02	0	0	101,744
2012	12	8,317,094	0	0	252.76	0	0	101,823
2013	1	8,409,042	0	0	253.66	7,524	-1,821	114,191
2013	2	7,528,345	0	0	254.22	6,714	-1,631	98,218
2013	3	8,419,646	0	0	254.66	6,443	-1,824	114,280
2013	4	8,574,008	0	0	255.25	6,805	-1,857	125,179
2013	5	9,875,896	0	0	255.51	7,731	-2,139	136,331
2013	6	10,252,553	0	0	255.78	8,704	-2,221	119,149

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Dummy November	Dummy November 2005	CPI for Energy (1982 - 84=100)	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for Smart Meters	Out-of-Model Adjustment for New/Modified Wholesale Contracts
2013	7	11,166,638	0	0	255.86	8,891	-2,419	127,974
2013	8	11,144,392	0	0	256.39	8,772	-2,414	133,218
2013	9	10,352,920	0	0	256.98	8,842	-2,242	121,502
2013	10	9,768,715	0	0	257.74	8,165	-2,116	117,174
2013	11	8,220,324	1	0	258.07	7,568	-1,780	85,534
2013	12	8,488,045	0	0	258.30	7,250	-1,838	85,863

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Out-of-Model Adjustment for Incremental DSM	Out-of-Model Adjustment for Hybrids
2001	7	9,562,389	0	0
2001	8	10,155,588	0	0
2001	9	8,848,883	0	0
2001	10	8,430,258	0	0
2001	11	7,043,087	0	0
2001	12	7,545,737	0	0
2002	1	7,760,946	0	0
2002	2	6,503,901	0	0
2002	3	7,990,149	0	0
2002	4	8,476,283	0	0
2002	5	9,406,970	0	0
2002	6	9,036,572	0	0
2002	7	10,071,087	0	0
2002	8	10,320,346	0	0
2002	9	10,060,592	0	0
2002	10	9,901,403	0	0
2002	11	7,553,628	0	0
2002	12	7,575,325	0	0
2003	1	8,196,046	0	0
2003	2	6,951,237	0	0
2003	3	8,869,654	0	0
2003	4	8,063,515	0	0
2003	5	9,977,015	0	0
2003	6	9,788,214	0	0
2003	7	10,773,171	0	0
2003	8	10,252,765	0	0
2003	9	9,900,915	0	0
2003	10	9,568,487	0	0
2003	11	8,204,690	0	0
2003	12	7,668,752	0	0
2004	1	7,673,433	0	0
2004	2	7,341,137	0	0
2004	3	7,858,341	0	0
2004	4	7,922,081	0	0
2004	5	9,576,175	0	0
2004	6	10,673,643	0	0
2004	7	10,937,914	0	0
2004	8	10,700,436	0	0
2004	9	9,621,164	0	0
2004	10	9,570,087	0	0
2004	11	8,129,488	0	0
2004	12	8,118,031	0	0
2005	1	8,045,152	0	0
2005	2	7,099,617	0	0
2005	3	8,340,298	0	0
2005	4	8,001,649	0	0
2005	5	9,672,947	0	0
2005	6	10,062,236	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Out-of-Model Adjustment for Incremental DSM	Out-of-Model Adjustment for Hybrids
2005	7	11,950,858	0	0
2005	8	11,930,141	0	0
2005	9	10,884,625	0	0
2005	10	9,187,793	0	0
2005	11	8,250,008	0	0
2005	12	8,017,565	0	0
2006	1	8,085,609	0	0
2006	2	7,497,292	0	0
2006	3	8,289,372	0	0
2006	4	9,064,955	0	0
2006	5	10,030,370	0	0
2006	6	10,714,052	0	0
2006	7	11,095,797	0	0
2006	8	11,564,017	0	0
2006	9	10,520,313	0	0
2006	10	9,930,813	0	0
2006	11	8,136,377	0	0
2006	12	8,477,014	0	0
2007	1	8,469,671	0	0
2007	2	7,527,571	0	0
2007	3	8,435,515	0	0
2007	4	8,579,552	0	0
2007	5	9,663,511	0	0
2007	6	10,343,275	0	0
2007	7	11,373,076	0	0
2007	8	12,110,271	0	0
2007	9	10,759,822	0	0
2007	10	10,632,392	0	0
2007	11	8,074,326	0	0
2007	12	8,563,233	0	0
2008	1	8,158,564	0	0
2008	2	7,896,972	0	0
2008	3	8,325,921	0	0
2008	4	8,619,990	0	0
2008	5	10,292,599	0	0
2008	6	10,508,760	0	0
2008	7	10,745,283	0	0
2008	8	11,090,020	0	0
2008	9	10,640,369	0	0
2008	10	9,367,637	0	0
2008	11	7,648,144	0	0
2008	12	7,806,098	0	0
2009	1	8,007,278	0	0
2009	2	7,235,663	0	0
2009	3	8,009,351	0	0
2009	4	8,493,145	0	0
2009	5	9,656,281	0	0
2009	6	10,367,469	0	0

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Out-of-Model Adjustment for Incremental DSM	Out-of-Model Adjustment for Hybrids
2009	7	11,007,925	0	0
2009	8	11,448,322	0	0
2009	9	10,342,759	0	0
2009	10	10,338,743	0	0
2009	11	8,115,012	0	0
2009	12	8,215,468	0	0
2010	1	9,390,504	0	0
2010	2	7,653,971	0	0
2010	3	7,879,752	0	0
2010	4	8,037,871	0	0
2010	5	10,395,115	0	0
2010	6	11,409,507	0	0
2010	7	11,649,520	0	0
2010	8	11,521,499	0	0
2010	9	10,666,454	0	0
2010	10	9,299,921	0	0
2010	11	7,811,927	0	0
2010	12	8,885,262	0	0
2011	1	7,922,768	0	0
2011	2	7,253,717	0	0
2011	3	8,196,117	0	0
2011	4	9,460,285	0	0
2011	5	10,098,308	0	0
2011	6	10,539,641	0	0
2011	7	11,211,614	0	0
2011	8	11,034,851	0	539
2011	9	10,233,834	0	522
2011	10	9,596,433	0	539
2011	11	7,985,879	0	522
2011	12	8,201,493	0	539
2012	1	8,281,180	-9,503	1,551
2012	2	7,411,022	-8,700	1,451
2012	3	8,307,816	-9,831	1,551
2012	4	8,483,674	-11,347	1,551
2012	5	9,791,945	-12,112	1,501
2012	6	10,204,539	-12,642	1,551
2012	7	11,110,969	-13,448	1,501
2012	8	11,088,953	-13,819	1,551
2012	9	10,281,836	-12,794	1,551
2012	10	9,662,478	-11,155	1,501
2012	11	8,079,384	-9,370	1,551
2012	12	8,317,094	-10,657	1,501
2013	1	8,409,042	-20,113	3,203
2013	2	7,528,345	-18,414	2,893
2013	3	8,419,646	-20,807	3,203
2013	4	8,574,008	-24,016	3,203
2013	5	9,875,896	-25,635	3,100
2013	6	10,252,553	-26,756	3,203

INPUTS FOR THE NET ENERGY FOR LOAD FORECAST

Year	Month	Net Energy For Load (mWh)	Out-of-Model Adjustment for Incremental DSM	Out-of-Model Adjustment for Hybrids
2013	7	11,166,638	-28,462	3,100
2013	8	11,144,392	-29,248	3,203
2013	9	10,352,920	-27,078	3,203
2013	10	9,768,715	-23,609	3,100
2013	11	8,220,324	-19,831	3,203
2013	12	8,488,045	-22,556	3,100

INPUTS FOR RESIDENTIAL SALES FORECAST

Year	Month	Residential Sales	Residential Customers	Cooling Degree Hours	Heating Degree Hours	Real per Capita Income weighted by Employed Population	Heating Degree Hours Lagged 1 Month	Cooling Degree Hours Lagged 1 Month	Real Retail Price of Gasoline Lagged 1 Month	Out-of-Model Adjustment for Advanced Metering Infrastructure	Out-of-Model Adjustment for NEL Reconciliation
		(mWh)		(Base - 72)	(Base - 66)	(Thousands 2005 $)	(Base - 66)	(Base - 72)	(Price per gallon)		
2000	1	3,338,737	3,384,081	23.46	123.92	14.03	65.25	24.42	0.81	0	0
2000	2	3,324,039	3,397,197	20.33	86.00	14.10	123.92	23.46	0.83	0	0
2000	3	3,031,640	3,407,888	65.96	11.04	14.12	86.00	20.33	0.86	0	0
2000	4	3,136,464	3,411,552	98.46	13.33	14.14	11.04	65.96	0.88	0	0
2000	5	3,431,287	3,404,302	192.08	0.25	14.18	13.33	98.46	0.93	0	0
2000	6	4,496,702	3,404,846	267.54	0.00	14.23	0.25	192.08	0.93	0	0
2000	7	4,725,599	3,407,511	291.00	0.00	14.31	0.00	267.54	0.93	0	0
2000	8	4,889,322	3,414,648	308.50	0.00	14.32	0.00	291.00	0.93	0	0
2000	9	4,933,001	3,420,410	295.59	0.00	14.33	0.00	308.50	0.93	0	0
2000	10	4,325,947	3,426,807	142.33	0.82	14.33	0.00	295.59	0.93	0	0
2000	11	3,281,063	3,437,316	66.42	34.50	14.34	0.82	142.33	0.93	0	0
2000	12	3,406,005	3,450,872	31.03	79.26	14.34	34.50	66.42	0.91	0	0
2001	1	4,323,201	3,466,059	9.49	288.03	14.36	79.26	31.03	0.89	0	0
2001	2	3,544,624	3,476,162	43.67	41.73	14.34	288.03	9.49	0.83	0	0
2001	3	3,229,239	3,485,376	70.90	46.11	14.30	41.73	43.67	0.86	0	0
2001	4	3,300,205	3,490,194	111.82	7.69	14.26	46.11	70.90	0.91	0	0
2001	5	3,351,686	3,483,167	134.04	0.42	14.24	7.69	111.82	0.99	0	0
2001	6	4,332,845	3,481,488	265.02	0.00	14.22	0.42	134.04	0.98	0	0
2001	7	4,674,659	3,486,754	265.98	0.00	14.21	0.00	265.02	0.94	0	0
2001	8	4,669,357	3,492,135	322.08	0.00	14.16	0.00	265.98	0.93	0	0
2001	9	5,033,366	3,495,624	248.00	0.00	14.11	0.00	322.08	0.88	0	0
2001	10	4,152,995	3,500,574	169.02	5.23	14.01	0.00	248.00	0.83	0	0
2001	11	3,506,377	3,507,818	66.64	6.43	14.04	5.23	169.02	0.77	0	0
2001	12	3,468,966	3,521,146	62.41	36.16	14.09	6.43	66.64	0.74	0	0
2002	1	4,001,236	3,530,913	30.56	113.70	14.19	36.16	62.41	0.72	0	0
2002	2	3,382,773	3,544,032	27.92	44.92	14.17	113.70	30.56	0.66	0	0
2002	3	3,238,840	3,554,186	78.34	39.48	14.13	44.92	27.92	0.70	0	0
2002	4	3,673,551	3,560,727	147.78	0.05	14.09	39.48	78.34	0.75	0	0
2002	5	4,333,351	3,557,221	216.70	0.00	14.05	0.05	147.78	0.82	0	0
2002	6	4,602,477	3,557,800	227.94	0.00	14.02	0.00	216.70	0.84	0	0
2002	7	4,524,709	3,562,956	280.25	0.00	13.96	0.00	227.94	0.84	0	0
2002	8	5,131,896	3,569,998	317.38	0.00	13.97	0.00	280.25	0.84	0	0
2002	9	5,147,817	3,574,767	315.92	0.00	13.99	0.00	317.38	0.83	0	0
2002	10	4,989,744	3,582,615	241.30	0.01	14.03	0.00	315.92	0.83	0	0
2002	11	4,275,123	3,593,622	102.90	34.73	13.99	0.01	241.30	0.80	0	0
2002	12	3,563,408	3,605,161	28.58	98.66	13.94	34.73	102.90	0.83	0	0
2003	1	4,131,540	3,613,511	7.43	246.00	13.85	98.66	28.58	0.87	0	0
2003	2	4,044,162	3,626,512	34.59	60.04	13.84	246.00	7.43	0.93	0	0
2003	3	3,842,431	3,637,857	126.72	1.94	13.87	60.04	34.59	0.92	0	0
2003	4	3,812,379	3,645,127	101.24	31.63	13.88	1.94	126.72	0.90	0	0
2003	5	4,242,899	3,642,135	229.04	0.00	13.90	31.63	101.24	0.87	0	0
2003	6	4,965,890	3,646,035	254.62	0.00	13.91	0.00	229.04	0.88	0	0
2003	7	5,255,879	3,649,435	325.18	0.00	13.89	0.00	254.62	0.90	0	0
2003	8	5,136,270	3,655,348	286.79	0.00	13.94	0.00	325.18	0.92	0	0
2003	9	5,163,382	3,663,254	283.48	0.00	14.00	0.00	286.79	0.91	0	0
2003	10	4,778,187	3,672,105	218.72	0.00	14.05	0.00	283.48	0.89	0	0
2003	11	4,233,840	3,684,389	127.69	3.80	14.13	0.00	218.72	0.85	0	0
2003	12	3,878,063	3,696,253	14.07	134.44	14.21	3.80	127.69	0.85	0	0
2004	1	4,031,104	3,704,268	20.03	126.50	14.28	134.44	14.07	0.87	0	0
2004	2	3,659,673	3,718,571	31.48	66.85	14.38	126.50	20.03	0.86	0	0
2004	3	3,489,378	3,731,504	47.38	40.94	14.48	66.85	31.48	0.92	0	0
2004	4	3,318,631	3,740,091	76.62	33.97	14.61	40.94	47.38	0.98	0	0
2004	5	3,901,509	3,740,143	132.54	13.83	14.66	33.97	76.62	1.07	0	0
2004	6	5,126,102	3,744,897	321.98	0.00	14.70	13.83	132.54	1.07	0	0
2004	7	5,710,403	3,752,041	310.79	0.00	14.72	0.00	321.98	1.05	0	0
2004	8	5,119,194	3,758,762	298.97	0.00	14.81	0.00	310.79	1.02	0	0
2004	9	5,116,744	3,755,791	298.37	0.00	14.90	0.00	298.97	1.03	0	0

INPUTS FOR RESIDENTIAL SALES FORECAST

Year	Month	Residential Sales	Residential Customers	Cooling Degree Hours	Heating Degree Hours	Real per Capita Income weighted by Employed Population	Heating Degree Hours Lagged 1 Month	Cooling Degree Hours Lagged 1 Month	Real Retail Price of Gasoline Lagged 1 Month	Out-of-Model Adjustment for Advanced Metering Infrastructure	Out-of-Model Adjustment for NEL Reconciliation
		(mWh)		(Base - 72)	(Base - 66)	(Thousands 2005 $)	(Base - 66)	(Base - 72)	(Price per gallon)		
2004	10	4,877,962	3,751,167	180.79	1.55	15.02	0.00	298.37	1.04	0	0
2004	11	4,190,791	3,768,160	89.16	9.20	15.08	1.55	180.79	1.07	0	0
2004	12	3,960,931	3,773,579	28.52	104.79	15.11	9.20	89.16	1.05	0	0
2005	1	4,149,469	3,786,666	23.88	103.07	15.15	104.79	28.52	1.04	0	0
2005	2	3,687,636	3,800,127	14.78	89.23	15.19	103.07	23.88	1.00	0	0
2005	3	3,559,528	3,810,317	55.04	78.94	15.25	89.23	14.78	1.02	0	0
2005	4	3,673,648	3,819,071	68.85	27.38	15.29	78.94	55.04	1.07	0	0
2005	5	3,875,025	3,820,847	151.25	0.75	15.38	27.38	68.85	1.10	0	0
2005	6	4,957,547	3,826,539	245.32	0.00	15.45	0.75	151.25	1.17	0	0
2005	7	5,661,223	3,832,397	350.24	0.00	15.57	0.00	245.32	1.24	0	0
2005	8	5,952,934	3,843,228	362.78	0.00	15.58	0.00	350.24	1.36	0	0
2005	9	5,901,465	3,845,823	314.84	0.00	15.58	0.00	362.78	1.35	0	0
2005	10	5,244,908	3,846,999	213.79	13.19	15.51	0.00	314.84	1.30	0	0
2005	11	3,800,106	3,849,102	86.27	16.32	15.62	13.19	213.79	1.28	0	0
2005	12	3,884,698	3,859,377	18.75	91.72	15.78	16.32	86.27	1.25	0	0
2006	1	4,154,740	3,872,326	28.91	97.43	15.98	91.72	18.75	1.22	0	0
2006	2	3,662,362	3,879,506	23.18	112.94	16.06	97.43	28.91	1.11	0	0
2006	3	3,556,452	3,890,134	48.31	53.94	16.11	112.94	23.18	1.19	0	0
2006	4	3,819,200	3,898,256	131.37	3.29	16.19	53.94	48.31	1.29	0	0
2006	5	4,421,975	3,895,260	175.99	1.33	16.20	3.29	131.37	1.42	0	0
2006	6	5,205,315	3,900,600	282.66	0.00	16.22	1.33	175.99	1.47	0	0
2006	7	5,542,797	3,902,901	283.19	0.00	16.22	0.00	282.66	1.46	0	0
2006	8	5,644,434	3,911,165	331.13	0.00	16.25	0.00	283.19	1.53	0	0
2006	9	5,487,448	3,918,631	281.35	0.00	16.29	0.00	331.13	1.43	0	0
2006	10	5,042,901	3,923,143	200.08	6.38	16.34	0.00	281.35	1.33	0	0
2006	11	4,106,098	3,935,484	70.37	58.54	16.34	6.38	200.08	1.17	0	0
2006	12	3,926,764	3,947,802	62.72	22.45	16.33	58.54	70.37	1.13	0	0
2007	1	4,283,866	3,955,335	55.45	29.07	16.34	22.45	62.72	1.15	0	0
2007	2	3,726,114	3,965,136	21.08	128.54	16.30	29.07	55.45	1.08	0	0
2007	3	3,644,338	3,975,438	64.46	26.46	16.25	128.54	21.08	1.19	0	0
2007	4	3,702,031	3,979,792	98.29	20.90	16.20	26.46	64.46	1.30	0	0
2007	5	4,204,168	3,978,583	159.46	1.25	16.16	20.90	98.29	1.50	0	0
2007	6	4,813,296	3,981,256	252.78	0.00	16.13	1.25	159.46	1.49	0	0
2007	7	5,633,379	3,986,068	307.42	0.00	16.10	0.00	252.78	1.45	0	0
2007	8	5,741,024	3,991,803	356.85	0.00	16.05	0.00	307.42	1.39	0	0
2007	9	6,003,705	3,990,293	302.42	0.00	15.99	0.00	356.85	1.39	0	0
2007	10	5,088,979	3,990,563	248.60	0.00	15.95	0.00	302.42	1.41	0	0
2007	11	4,284,518	3,990,843	87.50	22.37	15.87	0.00	248.60	1.42	0	0
2007	12	4,013,037	3,992,297	73.85	28.41	15.79	22.37	87.50	1.43	0	0
2008	1	4,234,068	3,995,414	36.13	78.70	15.71	28.41	73.85	1.44	0	0
2008	2	3,604,218	4,001,651	62.72	19.08	15.65	78.70	36.13	1.40	0	0
2008	3	3,598,528	4,003,023	56.94	43.84	15.57	19.08	62.72	1.48	0	0
2008	4	3,779,247	4,001,785	111.14	14.60	15.56	43.84	56.94	1.58	0	0
2008	5	4,283,255	3,996,910	216.40	0.22	15.40	14.60	111.14	1.71	0	0
2008	6	5,282,805	3,996,829	285.28	0.00	15.23	0.22	216.40	1.79	0	0
2008	7	5,301,896	3,991,810	277.51	0.00	14.99	0.00	285.28	1.80	0	0
2008	8	5,331,471	3,989,187	320.57	0.00	14.91	0.00	277.51	2.00	0	0
2008	9	5,632,133	3,985,030	318.91	0.00	14.85	0.00	320.57	1.81	0	0
2008	10	4,805,005	3,983,523	182.06	5.46	14.87	0.00	318.91	1.55	0	0
2008	11	3,672,851	3,981,138	53.24	74.94	14.69	5.46	182.06	1.22	0	0
2008	12	3,703,339	3,980,785	36.45	43.08	14.47	74.94	53.24	1.09	0	0
2009	1	3,931,715	3,981,732	24.48	125.58	14.19	43.08	36.45	1.04	0	0
2009	2	3,843,119	3,986,717	18.14	120.20	14.08	125.58	24.48	0.86	0	0
2009	3	3,354,308	3,987,693	49.88	42.95	14.02	120.20	18.14	0.90	0	0
2009	4	3,695,347	3,987,872	126.26	14.75	13.98	42.95	49.88	0.98	0	0
2009	5	4,232,804	3,984,699	193.36	0.00	13.86	14.75	126.26	1.06	0	0
2009	6	4,857,369	3,984,326	290.70	0.00	13.72	0.00	193.36	1.12	0	0

INPUTS FOR RESIDENTIAL SALES FORECAST

Year	Month	Residential Sales	Residential Customers	Cooling Degree Hours	Heating Degree Hours	Real per Capita Income weighted by Employed Population	Heating Degree Hours Lagged 1 Month	Cooling Degree Hours Lagged 1 Month	Real Retail Price of Gasoline Lagged 1 Month	Out-of-Model Adjustment for Advanced Metering Infrastructure	Out-of-Model Adjustment for NEL Reconciliation
		(mWh)		(Base - 72)	(Base - 66)	(Thousands 2005 $)	(Base - 66)	(Base - 72)	(Price per gallon)		
2009	7	5,575,986	3,984,488	318.41	0.00	13.53	0.00	290.70	1.15	0	0
2009	8	5,525,885	3,984,668	356.05	0.00	13.46	0.00	318.41	1.22	0	0
2009	9	5,490,522	3,981,876	310.26	0.00	13.43	0.00	356.05	1.22	0	0
2009	10	5,140,397	3,980,940	253.98	7.83	13.37	0.00	310.26	1.22	0	0
2009	11	4,356,809	3,984,445	124.51	23.57	13.34	7.83	253.98	1.22	0	0
2009	12	3,945,268	3,984,423	64.38	50.58	13.32	23.57	124.51	1.23	0	0
2010	1	5,216,443	3,988,092	18.12	275.40	13.24	50.58	64.38	1.24	0	0
2010	2	3,987,392	3,996,803	10.09	158.64	13.30	275.40	18.12	1.25	0	0
2010	3	3,850,643	4,002,154	14.19	152.51	13.38	158.64	10.09	1.28	0	0
2010	4	3,335,505	4,005,428	81.77	11.35	13.50	152.51	14.19	1.29	0	0
2010	5	4,299,631	4,006,527	235.21	0.00	13.51	11.35	81.77	1.33	0	0
2010	6	5,503,338	4,006,189	361.46	0.00	13.48	0.00	235.21	1.32	0	0
2010	7	5,922,255	4,006,320	352.69	0.00	13.45	0.00	361.46	1.31	0	0
2010	8	5,850,882	4,009,524	362.03	0.00	13.44	0.00	352.69	1.26	0	0
2010	9	5,646,215	4,007,495	329.82	0.00	13.44	0.00	362.03	1.27	0	0
2010	10	4,656,525	4,006,475	175.65	0.44	13.42	0.00	329.82	1.29	0	0
2010	11	3,910,019	4,007,538	88.25	30.87	13.43	0.44	175.65	1.29	0	0
2010	12	4,163,656	4,009,847	10.86	270.34	13.44	30.87	88.25	1.33	0	0
2011	1	4,535,157	4,015,002	14.09	134.01	13.44	270.34	10.86	1.38	0	0
2011	2	3,488,609	4,021,384	33.30	66.01	13.48	134.01	14.09	1.39	0	0
2011	3	3,412,863	4,027,937	71.93	28.62	13.52	66.01	33.30	1.49	0	0
2011	4	4,182,618	4,030,950	194.06	0.89	13.56	28.62	71.93	1.59	0	0
2011	5	4,641,773	4,029,779	225.87	0.00	13.59	0.89	194.06	1.78	0	0
2011	6	5,379,684	4,028,663	319.23	0.00	13.62	0.00	225.87	1.78	0	0
2011	7	5,462,625	4,028,593	328.04	0.00	13.65	0.00	319.23	1.73	0	0
2011	8	6,064,195	4,028,230	325.99	0.00	13.69	0.00	328.04	1.69	0	480,515
2011	9	5,189,305	4,028,460	294.49	0.00	13.72	0.00	325.99	1.64	0	-227,428
2011	10	4,675,915	4,027,450	197.84	2.55	13.78	0.00	294.49	1.59	0	-99,446
2011	11	3,955,305	4,028,014	91.13	24.98	13.79	2.55	197.84	1.53	0	-23,804
2011	12	3,725,317	4,029,343	40.38	81.65	13.79	24.98	91.13	1.51	0	24,775
2012	1	4,272,405	4,033,938	25.75	126.60	13.77	81.65	40.38	1.51	0	444,472
2012	2	3,636,997	4,038,849	30.15	82.24	13.79	126.60	25.75	1.46	0	-33,145
2012	3	3,531,295	4,044,450	59.18	51.67	13.83	82.24	30.15	1.51	0	-37,158
2012	4	3,564,124	4,047,186	111.83	14.17	13.86	51.67	59.18	1.57	0	-111,792
2012	5	4,205,344	4,047,623	191.26	1.96	13.89	14.17	111.83	1.68	0	69,868
2012	6	4,822,176	4,048,010	277.38	0.00	13.92	1.96	191.26	1.68	0	-62,758
2012	7	5,414,544	4,049,776	312.13	0.00	13.94	0.00	277.38	1.66	0	15,161
2012	8	5,439,617	4,053,623	325.99	0.00	13.97	0.00	312.13	1.64	0	-178,711
2012	9	5,185,651	4,053,543	294.49	0.00	14.00	0.00	325.99	1.61	0	-307,200
2012	10	4,674,039	4,054,086	197.84	2.55	14.04	0.00	294.49	1.59	0	-163,042
2012	11	3,962,615	4,055,945	91.13	24.98	14.05	2.55	197.84	1.57	0	-56,349
2012	12	3,748,599	4,058,455	40.38	81.65	14.07	24.98	91.13	1.55	0	6,024
2013	1	4,330,424	4,063,668	25.75	126.60	14.07	81.65	40.38	1.54	23,502	429,603
2013	2	3,694,690	4,069,091	30.15	82.24	14.11	126.60	25.75	1.48	20,421	-52,022
2013	3	3,584,625	4,075,032	59.18	51.67	14.15	82.24	30.15	1.54	23,195	-58,439
2013	4	3,604,443	4,078,626	111.83	14.17	14.18	51.67	59.18	1.62	23,477	-141,569
2013	5	4,236,450	4,080,871	191.26	1.96	14.22	14.17	111.83	1.75	26,730	34,079
2013	6	4,844,586	4,083,093	277.38	0.00	14.26	1.96	191.26	1.74	28,023	-123,700
2013	7	5,448,372	4,086,436	312.13	0.00	14.30	0.00	277.38	1.70	30,219	-55,042
2013	8	5,479,363	4,091,499	325.99	0.00	14.33	0.00	312.13	1.66	30,256	-256,761
2013	9	5,229,873	4,093,361	294.49	0.00	14.35	0.00	325.99	1.62	27,872	-383,148
2013	10	4,729,753	4,095,741	197.84	2.55	14.36	0.00	294.49	1.60	26,394	-218,248
2013	11	4,033,787	4,099,186	91.13	24.98	14.42	2.55	197.84	1.57	22,163	-92,150
2013	12	3,839,641	4,103,159	40.38	81.65	14.48	24.98	91.13	1.55	23,117	-15,712

Note: Cooling and Heating Degree Hours are on a fiscal basis.

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Commercial Customers	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Cooling Degree Hours (Base - 72)	Lagged Cooling Degree Hours (Base - 72)	Heating Degree Hours (Base - 66)	Inactive Ratio	Dummy December	Dummy January 2007
2000	1	2,807,879	410,919	14.03	23.46	24.42	123.92	4.77%	0.00	0
2000	2	2,644,788	411,290	14.10	20.33	23.46	86.00	4.60%	0.00	0
2000	3	2,789,522	412,265	14.12	65.96	20.33	11.04	4.61%	0.00	0
2000	4	2,837,119	413,385	14.14	98.46	65.96	13.33	4.90%	0.00	0
2000	5	2,930,921	414,109	14.18	192.08	98.46	0.25	5.18%	0.00	0
2000	6	3,316,917	414,878	14.23	267.54	192.08	0.00	5.22%	0.00	0
2000	7	3,385,066	415,352	14.31	291.00	267.54	0.00	5.26%	0.00	0
2000	8	3,452,666	416,280	14.32	308.50	291.00	0.00	5.27%	0.00	0
2000	9	3,524,204	417,493	14.33	295.59	308.50	0.00	5.23%	0.00	0
2000	10	3,274,747	418,213	14.33	142.33	295.59	0.82	5.17%	0.00	0
2000	11	3,001,960	419,055	14.34	66.42	142.33	34.50	4.94%	0.00	0
2000	12	3,035,373	420,276	14.34	31.03	66.42	79.26	4.81%	1.00	0
2001	1	2,916,410	421,718	14.36	9.49	31.03	288.03	4.62%	0.00	0
2001	2	2,777,191	423,096	14.34	43.67	9.49	41.73	4.47%	0.00	0
2001	3	2,898,617	423,639	14.30	70.90	43.67	46.11	4.47%	0.00	0
2001	4	2,915,096	424,616	14.26	111.82	70.90	7.69	4.76%	0.00	0
2001	5	2,976,875	426,058	14.24	134.04	111.82	0.42	5.01%	0.00	0
2001	6	3,359,306	426,218	14.22	265.02	134.04	0.00	5.13%	0.00	0
2001	7	3,455,453	427,095	14.21	265.98	265.02	0.00	5.19%	0.00	0
2001	8	3,407,261	428,133	14.16	322.08	265.98	0.00	5.17%	0.00	0
2001	9	3,585,695	428,679	14.11	248.00	322.08	0.00	5.19%	0.00	0
2001	10	3,312,158	429,436	14.01	169.02	248.00	5.23	5.17%	0.00	0
2001	11	3,119,098	429,714	14.04	66.64	169.02	6.43	5.02%	0.00	0
2001	12	3,237,334	430,471	14.09	62.41	66.64	36.16	4.28%	1.00	0
2002	1	3,135,767	430,850	14.19	30.56	62.41	113.70	4.67%	0.00	0
2002	2	3,016,458	431,813	14.17	27.92	30.56	44.92	4.56%	0.00	0
2002	3	2,867,916	432,652	14.13	78.34	27.92	39.48	4.50%	0.00	0
2002	4	3,133,342	433,718	14.09	147.78	78.34	0.05	4.73%	0.00	0
2002	5	3,359,922	434,426	14.05	216.70	147.78	0.00	4.93%	0.00	0
2002	6	3,517,205	435,100	14.02	227.94	216.70	0.00	5.02%	0.00	0
2002	7	3,448,619	435,899	13.96	280.25	227.94	0.00	5.11%	0.00	0
2002	8	3,590,456	437,275	13.97	317.38	280.25	0.00	5.10%	0.00	0
2002	9	3,706,315	437,247	13.99	315.92	317.38	0.00	5.09%	0.00	0
2002	10	3,635,787	437,171	14.03	241.30	315.92	0.01	5.02%	0.00	0
2002	11	3,417,955	438,362	13.99	102.90	241.30	34.73	4.82%	0.00	0
2002	12	3,199,324	439,245	13.94	28.58	102.90	98.66	4.74%	1.00	0
2003	1	3,089,186	439,718	13.85	7.43	28.58	246.00	4.65%	0.00	0
2003	2	3,000,725	440,526	13.84	34.59	7.43	60.04	4.55%	0.00	0
2003	3	3,266,679	441,273	13.87	126.72	34.59	1.94	4.55%	0.00	0
2003	4	3,217,390	442,374	13.88	101.24	126.72	31.63	4.76%	0.00	0
2003	5	3,377,096	443,371	13.90	229.04	101.24	0.00	4.87%	0.00	0
2003	6	3,689,926	443,371	13.91	254.62	229.04	0.00	4.94%	0.00	0
2003	7	3,690,514	445,030	13.89	325.18	254.62	0.00	4.95%	0.00	0
2003	8	3,729,379	445,870	13.94	286.79	325.18	0.00	5.00%	0.00	0
2003	9	3,783,616	446,934	14.00	283.48	286.79	0.00	4.96%	0.00	0
2003	10	3,663,077	448,097	14.05	218.72	283.48	0.00	4.80%	0.00	0
2003	11	3,479,591	449,181	14.13	127.69	218.72	3.80	4.57%	0.00	0

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Commercial Customers	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Cooling Degree Hours (Base - 72)	Lagged Cooling Degree Hours (Base - 72)	Heating Degree Hours (Base - 66)	Inactive Ratio	Dummy December	Dummy January 2007
2003	12	3,437,688	450,059	14.21	14.07	127.69	134.44	4.51%	1.00	0
2004	1	3,245,065	452,810	14.28	20.03	14.07	126.50	4.35%	0.00	0
2004	2	3,141,431	452,608	14.38	31.48	20.03	66.85	4.19%	0.00	0
2004	3	3,177,284	453,610	14.48	47.38	31.48	40.94	4.17%	0.00	0
2004	4	3,104,521	455,366	14.61	76.62	47.38	33.97	4.34%	0.00	0
2004	5	3,372,057	456,743	14.66	132.54	76.62	13.83	4.49%	0.00	0
2004	6	3,805,524	458,187	14.70	321.98	132.54	0.00	4.52%	0.00	0
2004	7	3,983,044	459,730	14.72	310.79	321.98	0.00	4.49%	0.00	0
2004	8	3,737,090	461,098	14.81	298.97	310.79	0.00	4.44%	0.00	0
2004	9	3,671,702	461,333	14.90	298.37	298.97	0.00	4.62%	0.00	0
2004	10	3,657,415	461,119	15.02	180.79	298.37	1.55	5.08%	0.00	0
2004	11	3,587,211	461,982	15.08	89.16	180.79	9.20	4.79%	0.00	0
2004	12	3,581,612	462,054	15.11	28.52	89.16	104.79	4.86%	1.00	0
2005	1	3,437,353	463,480	15.15	23.88	28.52	103.07	4.56%	0.00	0
2005	2	3,190,334	465,109	15.19	14.78	23.88	89.23	4.39%	0.00	0
2005	3	3,185,387	466,575	15.25	55.04	14.78	78.94	4.43%	0.00	0
2005	4	3,283,199	467,914	15.29	68.85	55.04	27.38	4.56%	0.00	0
2005	5	3,457,905	469,571	15.38	151.25	68.85	0.75	4.60%	0.00	0
2005	6	3,854,397	470,491	15.45	245.32	151.25	0.00	4.67%	0.00	0
2005	7	4,049,293	471,476	15.57	350.24	245.32	0.00	4.70%	0.00	0
2005	8	4,079,775	472,697	15.58	362.78	350.24	0.00	4.65%	0.00	0
2005	9	4,176,607	473,026	15.58	314.84	362.78	0.00	4.74%	0.00	0
2005	10	3,916,390	473,428	15.51	213.79	314.84	13.19	4.84%	0.00	0
2005	11	3,247,344	472,696	15.62	86.27	213.79	16.32	4.76%	0.00	0
2005	12	3,589,799	473,207	15.78	18.75	86.27	91.72	4.86%	1.00	0
2006	1	3,503,156	473,930	15.98	28.91	18.75	97.43	5.01%	0.00	0
2006	2	3,223,838	474,305	16.06	23.18	28.91	112.94	4.87%	0.00	0
2006	3	3,266,775	475,672	16.11	48.31	23.18	53.94	4.87%	0.00	0
2006	4	3,425,165	475,672	16.19	131.37	48.31	3.29	5.07%	0.00	0
2006	5	3,643,835	477,188	16.20	175.99	131.37	1.33	5.13%	0.00	0
2006	6	3,940,806	478,167	16.22	282.66	175.99	0.00	5.23%	0.00	0
2006	7	4,068,748	478,917	16.22	283.19	282.66	0.00	5.30%	0.00	0
2006	8	4,061,819	480,159	16.25	331.13	283.19	0.00	5.24%	0.00	0
2006	9	4,098,954	481,898	16.29	281.35	331.13	0.00	5.23%	0.00	0
2006	10	3,944,288	482,394	16.34	200.08	281.35	6.38	5.24%	0.00	0
2006	11	3,681,313	483,417	16.34	70.37	200.08	58.54	5.06%	0.00	0
2006	12	3,628,586	484,690	16.33	62.72	70.37	22.45	4.97%	1.00	0
2007	1	3,889,292	485,923	16.34	55.45	62.72	29.07	4.93%	0.00	1
2007	2	3,358,952	487,244	16.30	21.08	55.45	128.54	4.79%	0.00	0
2007	3	3,366,380	488,828	16.25	64.46	21.08	26.46	4.70%	0.00	0
2007	4	3,446,104	490,015	16.20	98.29	64.46	20.90	4.87%	0.00	0
2007	5	3,666,602	492,421	16.16	159.46	98.29	1.25	4.97%	0.00	0
2007	6	3,900,151	493,770	16.13	252.78	159.46	0.00	5.05%	0.00	0
2007	7	4,149,936	494,995	16.10	307.42	252.78	0.00	5.05%	0.00	0
2007	8	4,138,313	495,345	16.05	356.85	307.42	0.00	5.13%	0.00	0
2007	9	4,318,785	496,714	15.99	302.42	356.85	0.00	5.22%	0.00	0
2007	10	4,092,780	497,020	15.95	248.60	302.42	0.00	5.28%	0.00	0

INPUTS FOR COMMERCIAL SALES FORECAST

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2007	11	3,823,863	497,534	15.87	87.50	248.60	22.37	5.38%	0.00	0
2007	12	3,769,686	497,756	15.79	73.85	87.50	28.41	5.42%	1.00	0
2008	1	3,783,449	498,674	15.71	36.13	73.85	78.70	5.44%	0.00	0
2008	2	3,491,304	499,460	15.65	62.72	36.13	19.08	5.40%	0.00	0
2008	3	3,442,605	499,080	15.57	56.94	62.72	43.84	5.53%	0.00	0
2008	4	3,509,771	499,289	15.56	111.14	56.94	14.60	5.77%	0.00	0
2008	5	3,717,190	500,326	15.40	216.40	111.14	0.22	5.89%	0.00	0
2008	6	4,108,255	500,723	15.23	285.28	216.40	0.00	6.05%	0.00	0
2008	7	4,103,113	501,265	14.99	277.51	285.28	0.00	6.17%	0.00	0
2008	8	4,016,556	501,848	14.91	320.57	277.51	0.00	6.30%	0.00	0
2008	9	4,261,071	501,941	14.85	318.91	320.57	0.00	6.40%	0.00	0
2008	10	3,926,048	502,471	14.87	182.06	318.91	5.46	6.53%	0.00	0
2008	11	3,580,327	502,192	14.69	53.24	182.06	74.94	6.58%	0.00	0
2008	12	3,621,740	501,710	14.47	36.45	53.24	43.08	6.70%	1.00	0
2009	1	3,616,795	501,254	14.19	24.48	36.45	125.58	6.64%	0.00	0
2009	2	3,244,004	501,487	14.08	18.14	24.48	120.20	6.62%	0.00	0
2009	3	3,225,894	501,087	14.02	49.88	18.14	42.95	6.68%	0.00	0
2009	4	3,434,499	500,729	13.98	126.26	49.88	14.75	6.79%	0.00	0
2009	5	3,668,649	500,715	13.86	193.36	126.26	0.00	6.84%	0.00	0
2009	6	3,921,150	500,178	13.72	290.70	193.36	0.00	6.96%	0.00	0
2009	7	4,116,635	500,612	13.53	318.41	290.70	0.00	6.97%	0.00	0
2009	8	4,037,453	501,173	13.46	356.05	318.41	0.00	7.00%	0.00	0
2009	9	4,187,546	501,060	13.43	310.26	356.05	0.00	7.06%	0.00	0
2009	10	4,035,130	501,374	13.37	253.98	310.26	7.83	7.05%	0.00	0
2009	11	3,776,581	501,505	13.34	124.51	253.98	23.57	6.93%	0.00	0
2009	12	3,760,379	501,482	13.32	64.38	124.51	50.58	6.94%	1.00	0
2010	1	3,588,072	501,516	13.24	18.12	64.38	275.40	6.77%	0.00	0
2010	2	3,201,548	501,369	13.30	10.09	18.12	158.64	6.65%	0.00	0
2010	3	3,072,577	502,122	13.38	14.19	10.09	152.51	6.59%	0.00	0
2010	4	3,245,212	502,350	13.50	81.77	14.19	11.35	6.61%	0.00	0
2010	5	3,686,741	502,833	13.51	235.21	81.77	0.00	6.61%	0.00	0
2010	6	4,150,600	503,340	13.48	361.46	235.21	0.00	6.63%	0.00	0
2010	7	4,239,946	504,091	13.45	352.69	361.46	0.00	6.61%	0.00	0
2010	8	4,182,914	504,878	13.44	362.03	352.69	0.00	6.59%	0.00	0
2010	9	4,216,696	504,956	13.44	329.82	362.03	0.00	6.64%	0.00	0
2010	10	3,893,833	504,974	13.42	175.65	329.82	0.44	6.64%	0.00	0
2010	11	3,608,842	505,065	13.43	88.25	175.65	30.87	6.59%	0.00	0
2010	12	3,457,176	504,858	13.44	10.86	88.25	270.34	6.49%	1.00	0
2011	1	3,391,263	505,744	13.44	14.09	10.86	134.01	6.42%	0.00	0
2011	2	3,153,070	505,721	13.48	33.30	14.09	66.01	6.32%	0.00	0
2011	3	3,308,625	506,421	13.52	71.93	33.30	28.62	6.20%	0.00	0
2011	4	3,733,381	507,047	13.56	194.06	71.93	0.89	6.20%	0.00	0
2011	5	3,800,634	507,722	13.59	225.87	194.06	0.00	6.21%	0.00	0
2011	6	4,124,100	508,402	13.62	319.23	225.87	0.00	6.27%	0.00	0
2011	7	4,084,169	508,810	13.65	328.04	319.23	0.00	6.27%	0.00	0
2011	8	4,560,742	509,838	13.69	325.99	328.04	0.00	6.29%	0.00	0
2011	9	3,977,749	510,604	13.72	294.49	325.99	0.00	6.28%	0.00	0

INPUTS FOR COMMERCIAL SALES FORECAST

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2011	10	3,875,913	511,354	13.78	197.84	294.49	2.55	6.28%	0.00	0
2011	11	3,645,744	512,132	13.79	91.13	197.84	24.98	6.24%	0.00	0
2011	12	3,690,052	512,905	13.79	40.38	91.13	81.65	6.14%	1.00	0
2012	1	3,814,745	513,690	13.77	25.75	40.38	126.60	6.10%	0.00	0
2012	2	3,354,416	514,451	13.79	30.15	25.75	82.24	6.02%	0.00	0
2012	3	3,395,070	515,210	13.83	59.18	30.15	51.67	5.93%	0.00	0
2012	4	3,433,197	515,965	13.86	111.83	59.18	14.17	5.94%	0.00	0
2012	5	3,811,610	516,730	13.89	191.26	111.83	1.96	5.92%	0.00	0
2012	6	3,958,249	517,500	13.92	277.38	191.26	0.00	5.96%	0.00	0
2012	7	4,213,589	518,267	13.94	312.13	277.38	0.00	5.92%	0.00	0
2012	8	4,149,257	519,041	13.97	325.99	312.13	0.00	5.87%	0.00	0
2012	9	4,021,678	519,813	14.00	294.49	325.99	0.00	5.89%	0.00	0
2012	10	3,926,337	520,594	14.04	197.84	294.49	2.55	5.87%	0.00	0
2012	11	3,715,470	521,353	14.05	91.13	197.84	24.98	5.81%	0.00	0
2012	12	3,773,148	522,112	14.07	40.38	91.13	81.65	5.71%	1.00	0
2013	1	3,910,206	522,853	14.07	25.75	40.38	126.60	5.67%	0.00	0
2013	2	3,439,780	523,636	14.11	30.15	25.75	82.24	5.60%	0.00	0
2013	3	3,477,869	524,432	14.15	59.18	30.15	51.67	5.51%	0.00	0
2013	4	3,509,593	525,217	14.18	111.83	59.18	14.17	5.52%	0.00	0
2013	5	3,893,044	526,025	14.22	191.26	111.83	1.96	5.47%	0.00	0
2013	6	4,028,303	526,833	14.26	277.38	191.26	0.00	5.48%	0.00	0
2013	7	4,286,078	527,650	14.30	312.13	277.38	0.00	5.42%	0.00	0
2013	8	4,217,632	528,449	14.33	325.99	312.13	0.00	5.36%	0.00	0
2013	9	4,091,201	529,244	14.35	294.49	325.99	0.00	5.35%	0.00	0
2013	10	4,005,505	530,043	14.36	197.84	294.49	2.55	5.30%	0.00	0
2013	11	3,805,377	530,836	14.42	91.13	197.84	24.98	5.22%	0.00	0
2013	12	3,878,055	531,630	14.48	40.38	91.13	81.65	5.11%	1.00	0

Note: Cooling and Heating Degree Hours are on a fiscal basis.

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Out-of-Model Intercept Adjustment	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for NEL Reconciliation
2000	1	2,807,879	0	0	0.00
2000	2	2,644,788	0	0	0.00
2000	3	2,789,522	0	0	0.00
2000	4	2,837,119	0	0	0.00
2000	5	2,930,921	0	0	0.00
2000	6	3,316,917	0	0	0.00
2000	7	3,385,066	0	0	0.00
2000	8	3,452,666	0	0	0.00
2000	9	3,524,204	0	0	0.00
2000	10	3,274,747	0	0	0.00
2000	11	3,001,960	0	0	0.00
2000	12	3,035,373	0	0	0.00
2001	1	2,916,410	0	0	0.00
2001	2	2,777,191	0	0	0.00
2001	3	2,898,617	0	0	0.00
2001	4	2,915,096	0	0	0.00
2001	5	2,976,875	0	0	0.00
2001	6	3,359,306	0	0	0.00
2001	7	3,455,453	0	0	0.00
2001	8	3,407,261	0	0	0.00
2001	9	3,585,695	0	0	0.00
2001	10	3,312,158	0	0	0.00
2001	11	3,119,098	0	0	0.00
2001	12	3,237,334	0	0	0.00
2002	1	3,135,767	0	0	0.00
2002	2	3,016,458	0	0	0.00
2002	3	2,867,916	0	0	0.00
2002	4	3,133,342	0	0	0.00
2002	5	3,359,922	0	0	0.00
2002	6	3,517,205	0	0	0.00
2002	7	3,448,619	0	0	0.00
2002	8	3,590,456	0	0	0.00
2002	9	3,706,315	0	0	0.00
2002	10	3,635,787	0	0	0.00
2002	11	3,417,955	0	0	0.00
2002	12	3,199,324	0	0	0.00
2003	1	3,089,186	0	0	0.00
2003	2	3,000,725	0	0	0.00
2003	3	3,266,679	0	0	0.00
2003	4	3,217,390	0	0	0.00
2003	5	3,377,096	0	0	0.00
2003	6	3,689,926	0	0	0.00
2003	7	3,690,514	0	0	0.00
2003	8	3,729,379	0	0	0.00
2003	9	3,783,616	0	0	0.00
2003	10	3,663,077	0	0	0.00
2003	11	3,479,591	0	0	0.00

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Out-of-Model Intercept Adjustment	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for NEL Reconciliation
2003	12	3,437,688	0	0	0.00
2004	1	3,245,065	0	0	0.00
2004	2	3,141,431	0	0	0.00
2004	3	3,177,284	0	0	0.00
2004	4	3,104,521	0	0	0.00
2004	5	3,372,057	0	0	0.00
2004	6	3,805,524	0	0	0.00
2004	7	3,983,044	0	0	0.00
2004	8	3,737,090	0	0	0.00
2004	9	3,671,702	0	0	0.00
2004	10	3,657,415	0	0	0.00
2004	11	3,587,211	0	0	0.00
2004	12	3,581,612	0	0	0.00
2005	1	3,437,353	0	0	0.00
2005	2	3,190,334	0	0	0.00
2005	3	3,185,387	0	0	0.00
2005	4	3,283,199	0	0	0.00
2005	5	3,457,905	0	0	0.00
2005	6	3,854,397	0	0	0.00
2005	7	4,049,293	0	0	0.00
2005	8	4,079,775	0	0	0.00
2005	9	4,176,607	0	0	0.00
2005	10	3,916,390	0	0	0.00
2005	11	3,247,344	0	0	0.00
2005	12	3,589,799	0	0	0.00
2006	1	3,503,156	0	0	0.00
2006	2	3,223,838	0	0	0.00
2006	3	3,266,775	0	0	0.00
2006	4	3,425,165	0	0	0.00
2006	5	3,643,835	0	0	0.00
2006	6	3,940,806	0	0	0.00
2006	7	4,068,748	0	0	0.00
2006	8	4,061,819	0	0	0.00
2006	9	4,098,954	0	0	0.00
2006	10	3,944,288	0	0	0.00
2006	11	3,681,313	0	0	0.00
2006	12	3,628,586	0	0	0.00
2007	1	3,889,292	0	0	0.00
2007	2	3,358,952	0	0	0.00
2007	3	3,366,380	0	0	0.00
2007	4	3,446,104	0	0	0.00
2007	5	3,666,602	0	0	0.00
2007	6	3,900,151	0	0	0.00
2007	7	4,149,936	0	0	0.00
2007	8	4,138,313	0	0	0.00
2007	9	4,318,785	0	0	0.00
2007	10	4,092,780	0	0	0.00

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Out-of-Model Intercept Adjustment	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for NEL Reconciliation
2007	11	3,823,863	0	0	0.00
2007	12	3,769,686	0	0	0.00
2008	1	3,783,449	0	0	0.00
2008	2	3,491,304	0	0	0.00
2008	3	3,442,605	0	0	0.00
2008	4	3,509,771	0	0	0.00
2008	5	3,717,190	0	0	0.00
2008	6	4,108,255	0	0	0.00
2008	7	4,103,113	0	0	0.00
2008	8	4,016,556	0	0	0.00
2008	9	4,261,071	0	0	0.00
2008	10	3,926,048	0	0	0.00
2008	11	3,580,327	0	0	0.00
2008	12	3,621,740	0	0	0.00
2009	1	3,616,795	0	0	0.00
2009	2	3,244,004	0	0	0.00
2009	3	3,225,894	0	0	0.00
2009	4	3,434,499	0	0	0.00
2009	5	3,668,649	0	0	0.00
2009	6	3,921,150	0	0	0.00
2009	7	4,116,635	0	0	0.00
2009	8	4,037,453	0	0	0.00
2009	9	4,187,546	0	0	0.00
2009	10	4,035,130	0	0	0.00
2009	11	3,776,581	0	0	0.00
2009	12	3,760,379	0	0	0.00
2010	1	3,588,072	0	0	0.00
2010	2	3,201,548	0	0	0.00
2010	3	3,072,577	0	0	0.00
2010	4	3,245,212	0	0	0.00
2010	5	3,686,741	0	0	0.00
2010	6	4,150,600	0	0	0.00
2010	7	4,239,946	0	0	0.00
2010	8	4,182,914	0	0	0.00
2010	9	4,216,696	0	0	0.00
2010	10	3,893,833	0	0	0.00
2010	11	3,608,842	0	0	0.00
2010	12	3,457,176	0	0	0.00
2011	1	3,391,263	0	0	0.00
2011	2	3,153,070	0	0	0.00
2011	3	3,308,625	0	0	0.00
2011	4	3,733,381	0	0	0.00
2011	5	3,800,634	0	0	0.00
2011	6	4,124,100	0	0	0.00
2011	7	4,084,169	0	0	0.00
2011	8	4,560,742	-48,942	0	361,384
2011	9	3,977,749	-48,391	0	-174,330

INPUTS FOR COMMERCIAL SALES FORECAST

Year	Month	Commercial Sales (mWh)	Out-of-Model Intercept Adjustment	Out-of-Model Adjustment for Economic Development Rate	Out-of-Model Adjustment for NEL Reconciliation
2011	10	3,875,913	-46,133	0	-82,432
2011	11	3,645,744	-42,745	0	-21,941
2011	12	3,690,052	-42,720	0	24,541
2012	1	3,814,745	-39,834	0	396,861
2012	2	3,354,416	-39,451	0	-30,570
2012	3	3,395,070	-39,985	0	-35,724
2012	4	3,433,197	-41,268	0	-107,686
2012	5	3,811,610	-43,685	0	63,326
2012	6	3,958,249	-46,732	0	-51,514
2012	7	4,213,589	-48,970	0	11,799
2012	8	4,149,257	-49,947	0	-136,318
2012	9	4,021,678	-49,648	0	-238,245
2012	10	3,926,337	-47,356	0	-136,961
2012	11	3,715,470	-43,918	0	-52,835
2012	12	3,773,148	-43,904	0	6,064
2013	1	3,910,206	-40,969	7,053	387,915
2013	2	3,439,780	-40,580	6,293	-48,433
2013	3	3,477,869	-41,124	6,039	-56,699
2013	4	3,509,593	-42,435	6,379	-137,843
2013	5	3,893,044	-44,923	7,247	31,317
2013	6	4,028,303	-48,052	8,158	-102,858
2013	7	4,286,078	-50,360	8,334	-43,300
2013	8	4,217,632	-51,362	8,222	-197,636
2013	9	4,091,201	-51,078	8,288	-299,727
2013	10	4,005,505	-48,748	7,654	-184,829
2013	11	3,805,377	-45,281	7,094	-86,932
2013	12	3,878,055	-45,303	6,795	-15,870

INPUTS FOR THE SMALL INDUSTRIAL SALES FORECAST

Year	Month	Small Industrial Sales (mwh)	Small Industrial Customers	Real Disposable Personal Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Heating Degree Hours (Base - 66)	Dummy February 2006
2002	1	7,077	13,053	489,926.72	30.56	113.70	0
2002	2	6,484	13,158	491,923.03	27.92	44.92	0
2002	3	6,455	13,152	491,297.93	78.34	39.48	0
2002	4	6,982	13,023	491,331.09	147.78	0.05	0
2002	5	7,572	13,159	490,816.93	216.70	0.00	0
2002	6	7,897	13,263	491,112.12	227.94	0.00	0
2002	7	8,397	12,885	490,687.71	280.25	0.00	0
2002	8	8,135	12,978	491,512.28	317.38	0.00	0
2002	9	8,508	13,755	492,532.44	315.92	0.00	0
2002	10	8,538	14,057	492,828.55	241.30	0.01	0
2002	11	8,056	14,153	494,702.60	102.90	34.73	0
2002	12	7,197	14,270	496,910.34	28.58	98.66	0
2003	1	7,703	14,127	499,022.36	7.43	246.00	0
2003	2	7,478	14,254	501,279.61	34.59	60.04	0
2003	3	7,188	14,494	503,368.20	126.72	1.94	0
2003	4	7,543	14,558	505,745.28	101.24	31.63	0
2003	5	8,081	14,703	507,362.75	229.04	0.00	0
2003	6	9,124	14,910	509,134.33	254.62	0.00	0
2003	7	9,145	14,972	509,819.54	325.18	0.00	0
2003	8	9,392	15,159	513,104.44	286.79	0.00	0
2003	9	9,666	15,266	516,681.19	283.48	0.00	0
2003	10	8,913	15,508	521,241.47	218.72	0.00	0
2003	11	8,386	15,737	523,263.60	127.69	3.80	0
2003	12	7,852	15,748	524,867.01	14.07	134.44	0
2004	1	8,025	15,680	525,443.18	20.03	126.50	0
2004	2	7,276	15,726	528,641.37	31.48	66.85	0
2004	3	7,305	15,911	532,434.20	47.38	40.94	0
2004	4	7,412	16,216	536,674.14	76.62	33.97	0
2004	5	8,186	16,230	539,516.14	132.54	13.83	0
2004	6	9,925	16,398	542,071.97	321.98	0.00	0
2004	7	10,627	16,936	544,082.66	310.79	0.00	0
2004	8	9,100	17,354	547,866.30	298.97	0.00	0
2004	9	10,148	17,095	551,457.26	298.37	0.00	0
2004	10	10,022	17,044	557,880.11	180.79	1.55	0
2004	11	9,042	16,593	557,601.89	89.16	9.20	0
2004	12	8,415	16,185	556,240.43	28.52	104.79	0
2005	1	8,509	17,107	553,137.77	23.88	103.07	0
2005	2	7,837	17,539	554,467.87	14.78	89.23	0
2005	3	7,789	17,754	557,196.86	55.04	78.94	0
2005	4	7,702	17,974	559,792.42	68.85	27.38	0
2005	5	8,364	18,351	562,284.36	151.25	0.75	0
2005	6	10,101	18,647	564,066.58	245.32	0.00	0
2005	7	11,096	18,690	566,592.91	350.24	0.00	0
2005	8	11,780	19,142	567,257.01	362.78	0.00	0
2005	9	11,779	18,999	568,447.72	314.84	0.00	0
2005	10	10,969	19,011	566,540.84	213.79	13.19	0
2005	11	8,327	18,699	571,786.46	86.27	16.32	0
2005	12	8,380	17,892	578,167.10	18.75	91.72	0
2006	1	8,148	17,711	586,226.44	28.91	97.43	0
2006	2	7,880	18,876	590,137.26	23.18	112.94	1
2006	3	7,966	19,023	592,421.06	48.31	53.94	0
2006	4	8,702	19,086	596,130.14	131.37	3.29	0
2006	5	9,707	19,496	597,092.63	175.99	1.33	0
2006	6	11,115	19,587	598,100.91	282.66	0.00	0
2006	7	11,796	19,414	598,414.11	283.19	0.00	0

INPUTS FOR THE SMALL INDUSTRIAL SALES FORECAST

Year	Month	Small Industrial Sales (mwh)	Small Industrial Customers	Real Disposable Personal Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Heating Degree Hours (Base - 66)	Dummy February 2006
2006	8	12,603	19,525	600,414.43	331.13	0.00	0
2006	9	12,387	19,430	602,618.59	281.35	0.00	0
2006	10	11,638	19,172	605,669.92	200.08	6.38	0
2006	11	9,842	19,271	606,781.00	70.37	58.54	0
2006	12	9,562	19,424	607,209.95	62.72	22.45	0
2007	1	9,726	19,205	608,328.72	55.45	29.07	0
2007	2	8,769	19,191	608,011.26	21.08	128.54	0
2007	3	8,715	18,863	607,770.97	64.46	26.46	0
2007	4	8,992	18,238	606,810.08	98.29	20.90	0
2007	5	9,513	17,805	607,645.40	159.46	1.25	0
2007	6	10,860	17,111	608,591.64	252.78	0.00	0
2007	7	12,295	16,416	610,472.58	307.42	0.00	0
2007	8	12,034	15,808	609,857.67	356.85	0.00	0
2007	9	12,096	15,407	609,136.84	302.42	0.00	0
2007	10	10,526	14,895	606,236.81	248.60	0.00	0
2007	11	8,689	14,344	608,462.45	87.50	22.37	0
2007	12	7,701	13,750	611,822.30	73.85	28.41	0
2008	1	7,438	13,210	615,932.11	36.13	78.70	0
2008	2	6,768	12,770	618,311.89	62.72	19.08	0
2008	3	6,452	12,308	619,152.66	56.94	43.84	0
2008	4	6,707	12,024	623,273.03	111.14	14.60	0
2008	5	7,033	11,713	620,106.90	216.40	0.22	0
2008	6	8,034	11,518	616,291.12	285.28	0.00	0
2008	7	7,893	11,308	609,993.64	277.51	0.00	0
2008	8	7,795	11,079	609,641.04	320.57	0.00	0
2008	9	8,593	10,956	610,947.61	318.91	0.00	0
2008	10	7,496	10,723	611,720.27	182.06	5.46	0
2008	11	6,235	10,448	613,030.34	53.24	74.94	0
2008	12	5,696	10,111	614,010.74	36.45	43.08	0
2009	1	5,608	9,604	615,124.24	24.48	125.58	0
2009	2	4,647	9,269	616,416.38	18.14	120.20	0
2009	3	4,848	9,017	617,237.80	49.88	42.95	0
2009	4	4,865	8,693	620,624.46	126.26	14.75	0
2009	5	5,109	8,514	618,089.69	193.36	0.00	0
2009	6	5,777	8,254	614,646.82	290.70	0.00	0
2009	7	6,206	8,132	609,832.25	318.41	0.00	0
2009	8	5,682	7,973	608,507.93	356.05	0.00	0
2009	9	5,613	7,855	608,343.11	310.26	0.00	0
2009	10	5,454	7,778	607,533.56	253.98	7.83	0
2009	11	4,780	7,703	607,520.62	124.51	23.57	0
2009	12	4,707	7,561	607,732.20	64.38	50.58	0
2010	1	4,960	7,383	606,359.04	18.12	275.40	0
2010	2	4,120	7,353	608,746.41	10.09	158.64	0
2010	3	3,951	7,302	611,607.47	14.19	152.51	0
2010	4	4,072	7,314	615,832.85	81.77	11.35	0
2010	5	4,422	7,236	616,672.72	235.21	0.00	0
2010	6	4,905	7,263	616,659.88	361.46	0.00	0
2010	7	5,170	7,255	616,494.56	352.69	0.00	0
2010	8	5,121	7,238	617,138.74	362.03	0.00	0
2010	9	5,204	7,344	618,031.28	329.82	0.00	0
2010	10	4,785	7,424	619,713.63	175.65	0.44	0
2010	11	4,147	7,307	619,389.86	88.25	30.87	0
2010	12	4,230	7,177	618,667.65	10.86	270.34	0
2011	1	4,354	7,143	617,271.40	14.09	134.01	0
2011	2	3,792	7,145	617,517.39	33.30	66.01	0

INPUTS FOR THE SMALL INDUSTRIAL SALES FORECAST

Year	Month	Small Industrial Sales (mwh)	Small Industrial Customers	Real Disposable Personal Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Heating Degree Hours (Base - 66)	Dummy February 2006
2011	3	3,924	7,084	618,394.59	71.93	28.62	0
2011	4	4,448	7,136	618,633.10	194.06	0.89	0
2011	5	4,755	7,192	620,074.55	225.87	0.00	0
2011	6	4,767	7,161	621,635.13	319.23	0.00	0
2011	7	4,798	7,148	623,223.72	328.04	0.00	0
2011	8	4,820	7,136	624,890.12	325.99	0.00	0
2011	9	4,719	7,140	626,208.63	294.49	0.00	0
2011	10	4,351	7,157	628,860.61	197.84	2.55	0
2011	11	3,961	7,165	628,424.05	91.13	24.98	0
2011	12	3,888	7,188	627,634.33	40.38	81.65	0
2012	1	3,937	7,209	625,777.53	25.75	126.60	0
2012	2	3,881	7,235	626,555.52	30.15	82.24	0
2012	3	3,957	7,250	628,002.80	59.18	51.67	0
2012	4	4,120	7,264	629,572.96	111.83	14.17	0
2012	5	4,448	7,269	630,550.83	191.26	1.96	0
2012	6	4,841	7,295	631,256.34	277.38	0.00	0
2012	7	5,018	7,327	631,827.91	312.13	0.00	0
2012	8	5,103	7,353	632,973.32	325.99	0.00	0
2012	9	4,997	7,392	634,066.08	294.49	0.00	0
2012	10	4,608	7,430	636,241.67	197.84	2.55	0
2012	11	4,210	7,475	635,825.92	91.13	24.98	0
2012	12	4,126	7,503	635,018.53	40.38	81.65	0
2013	1	4,171	7,528	633,347.03	25.75	126.60	0
2013	2	4,099	7,545	633,782.26	30.15	82.24	0
2013	3	4,185	7,583	634,905.49	59.18	51.67	0
2013	4	4,364	7,626	635,601.27	111.83	14.17	0
2013	5	4,730	7,668	636,990.01	191.26	1.96	0
2013	6	5,157	7,712	638,361.13	277.38	0.00	0
2013	7	5,352	7,755	639,520.65	312.13	0.00	0
2013	8	5,457	7,802	641,116.09	325.99	0.00	0
2013	9	5,345	7,842	642,921.64	294.49	0.00	0
2013	10	4,927	7,880	644,248.42	197.84	2.55	0
2013	11	4,513	7,922	646,594.54	91.13	24.98	0
2013	12	4,441	7,954	649,116.62	40.38	81.65	0

Note: All Cooling and Heating Degree Hours are on a fiscal basis.

INPUTS FOR THE MEDIUM INDUSTRIAL SALES FORECAST

Year	Month	Medium Industrial Sales (mWh)	Disposable Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Dummy February 2006
2000	1	38,149	446,541.65	23.46	0
2000	2	36,677	448,661.23	20.33	0
2000	3	39,199	449,692.20	65.96	0
2000	4	38,848	451,031.86	98.46	0
2000	5	39,239	452,131.39	192.08	0
2000	6	42,015	453,444.98	267.54	0
2000	7	39,785	454,908.33	291.00	0
2000	8	40,851	455,816.90	308.50	0
2000	9	40,287	456,744.54	295.59	0
2000	10	39,343	456,864.92	142.33	0
2000	11	38,028	458,978.17	66.42	0
2000	12	39,398	461,312.11	31.03	0
2001	1	37,333	464,680.54	9.49	0
2001	2	36,193	465,584.94	43.67	0
2001	3	37,987	465,826.73	70.90	0
2001	4	37,789	466,290.44	111.82	0
2001	5	38,287	466,566.07	134.04	0
2001	6	39,994	466,898.73	265.02	0
2001	7	37,384	467,073.51	265.98	0
2001	8	37,365	466,991.48	322.08	0
2001	9	38,491	467,869.16	248.00	0
2001	10	36,775	464,610.03	169.02	0
2001	11	35,914	471,038.30	66.64	0
2001	12	37,254	478,523.00	62.41	0
2002	1	36,027	489,926.72	30.56	0
2002	2	35,485	491,923.03	27.92	0
2002	3	32,437	491,297.93	78.34	0
2002	4	40,557	491,331.09	147.78	0
2002	5	39,934	490,816.93	216.70	0
2002	6	40,991	491,112.12	227.94	0
2002	7	37,161	490,687.71	280.25	0
2002	8	38,024	491,512.28	317.38	0
2002	9	38,032	492,532.44	315.92	0
2002	10	37,318	492,828.55	241.30	0
2002	11	36,865	494,702.60	102.90	0
2002	12	36,677	496,910.34	28.58	0
2003	1	35,460	499,022.36	7.43	0
2003	2	35,943	501,279.61	34.59	0
2003	3	36,562	503,368.20	126.72	0
2003	4	35,346	505,745.28	101.24	0
2003	5	36,354	507,362.75	229.04	0
2003	6	37,711	509,134.33	254.62	0
2003	7	36,707	509,819.54	325.18	0
2003	8	35,721	513,104.44	286.79	0
2003	9	36,307	516,681.19	283.48	0
2003	10	35,614	521,241.47	218.72	0
2003	11	36,499	523,263.60	127.69	0
2003	12	36,809	524,867.01	14.07	0
2004	1	35,496	525,443.18	20.03	0
2004	2	34,837	528,641.37	31.48	0
2004	3	34,559	532,434.20	47.38	0
2004	4	33,458	536,674.14	76.62	0
2004	5	34,266	539,516.14	132.54	0
2004	6	37,692	542,071.97	321.98	0

INPUTS FOR THE MEDIUM INDUSTRIAL SALES FORECAST

Year	Month	Medium Industrial Sales (mWh)	Disposable Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Dummy February 2006
2004	7	37,214	544,082.66	310.79	0
2004	8	34,640	547,866.30	298.97	0
2004	9	34,184	551,457.26	298.37	0
2004	10	33,774	557,880.11	180.79	0
2004	11	34,792	557,601.89	89.16	0
2004	12	34,916	556,240.43	28.52	0
2005	1	38,487	553,137.77	23.88	0
2005	2	41,547	554,467.87	14.78	0
2005	3	35,932	557,196.86	55.04	0
2005	4	35,572	559,792.42	68.85	0
2005	5	36,210	562,284.36	151.25	0
2005	6	37,869	564,066.58	245.32	0
2005	7	37,500	566,592.91	350.24	0
2005	8	38,471	567,257.01	362.78	0
2005	9	35,929	568,447.72	314.84	0
2005	10	36,496	566,540.84	213.79	0
2005	11	30,215	571,786.46	86.27	0
2005	12	33,599	578,167.10	18.75	0
2006	1	35,565	586,226.44	28.91	0
2006	2	30,943	590,137.26	23.18	1
2006	3	32,401	592,421.06	48.31	0
2006	4	33,923	596,130.14	131.37	0
2006	5	34,276	597,092.63	175.99	0
2006	6	36,381	598,100.91	282.66	0
2006	7	35,438	598,414.11	283.19	0
2006	8	35,293	600,414.43	331.13	0
2006	9	34,984	602,618.59	281.35	0
2006	10	34,574	605,669.92	200.08	0
2006	11	34,043	606,781.00	70.37	0
2006	12	34,598	607,209.95	62.72	0
2007	1	35,852	608,328.72	55.45	0
2007	2	32,394	608,011.26	21.08	0
2007	3	33,180	607,770.97	64.46	0
2007	4	32,923	606,810.08	98.29	0
2007	5	33,504	607,645.40	159.46	0
2007	6	34,350	608,591.64	252.78	0
2007	7	35,117	610,472.58	307.42	0
2007	8	31,977	609,857.67	356.85	0
2007	9	34,835	609,136.84	302.42	0
2007	10	33,723	606,236.81	248.60	0
2007	11	32,674	608,462.45	87.50	0
2007	12	32,179	611,822.30	73.85	0
2008	1	32,653	615,932.11	36.13	0
2008	2	29,998	618,311.89	62.72	0
2008	3	28,668	619,152.66	56.94	0
2008	4	28,899	623,273.03	111.14	0
2008	5	31,032	620,106.90	216.40	0
2008	6	31,678	616,291.12	285.28	0
2008	7	29,745	609,993.64	277.51	0
2008	8	29,312	609,641.04	320.57	0
2008	9	30,635	610,947.61	318.91	0
2008	10	27,804	611,720.27	182.06	0
2008	11	26,581	613,030.34	53.24	0
2008	12	27,195	614,010.74	36.45	0

INPUTS FOR THE MEDIUM INDUSTRIAL SALES FORECAST

Year	Month	Medium Industrial Sales (mWh)	Disposable Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Dummy February 2006
2009	1	27,154	615,124.24	24.48	0
2009	2	26,067	616,416.38	18.14	0
2009	3	25,478	617,237.80	49.88	0
2009	4	26,071	620,624.46	126.26	0
2009	5	27,865	618,089.69	193.36	0
2009	6	27,645	614,646.82	290.70	0
2009	7	28,396	609,832.25	318.41	0
2009	8	25,715	608,507.93	356.05	0
2009	9	26,739	608,343.11	310.26	0
2009	10	26,218	607,533.56	253.98	0
2009	11	25,482	607,520.62	124.51	0
2009	12	26,126	607,732.20	64.38	0
2010	1	25,730	606,359.04	18.12	0
2010	2	23,487	608,746.41	10.09	0
2010	3	22,977	611,607.47	14.19	0
2010	4	23,894	615,832.85	81.77	0
2010	5	25,139	616,672.72	235.21	0
2010	6	25,823	616,659.88	361.46	0
2010	7	25,001	616,494.56	352.69	0
2010	8	25,883	617,138.74	362.03	0
2010	9	25,407	618,031.28	329.82	0
2010	10	24,437	619,713.63	175.65	0
2010	11	23,636	619,389.86	88.25	0
2010	12	23,180	618,667.65	10.86	0
2011	1	22,742	617,271.40	14.09	0
2011	2	20,807	617,517.39	33.30	0
2011	3	21,674	618,394.59	71.93	0
2011	4	24,070	618,633.10	194.06	0
2011	5	23,857	620,074.55	225.87	0
2011	6	25,191	621,635.13	319.23	0
2011	7	23,386	623,223.72	328.04	0
2011	8	23,739	624,890.12	325.99	0
2011	9	23,301	626,208.63	294.49	0
2011	10	23,130	628,860.61	197.84	0
2011	11	22,058	628,424.05	91.13	0
2011	12	21,939	627,634.33	40.38	0
2012	1	21,244	625,777.53	25.75	0
2012	2	19,193	626,555.52	30.15	0
2012	3	19,961	628,002.80	59.18	0
2012	4	21,500	629,572.96	111.83	0
2012	5	21,905	630,550.83	191.26	0
2012	6	23,092	631,256.34	277.38	0
2012	7	21,612	631,827.91	312.13	0
2012	8	22,138	632,973.32	325.99	0
2012	9	21,689	634,066.08	294.49	0
2012	10	21,469	636,241.67	197.84	0
2012	11	20,391	635,825.92	91.13	0
2012	12	20,257	635,018.53	40.38	0
2013	1	19,582	633,347.03	25.75	0
2013	2	17,556	633,782.26	30.15	0
2013	3	18,298	634,905.49	59.18	0
2013	4	19,769	635,601.27	111.83	0
2013	5	20,214	636,990.01	191.26	0
2013	6	21,441	638,361.13	277.38	0

INPUTS FOR THE MEDIUM INDUSTRIAL SALES FORECAST

Year	Month	Medium Industrial Sales (mWh)	Disposable Income (Millions 2005 $)	Cooling Degree Hours (Base - 72)	Dummy February 2006
2013	7	20,039	639,520.65	312.13	0
2013	8	20,587	641,116.09	325.99	0
2013	9	20,182	642,921.64	294.49	0
2013	10	19,891	644,248.42	197.84	0
2013	11	18,972	646,594.54	91.13	0
2013	12	19,027	649,116.62	40.38	0

Note: Cooling Degree Hours are on a fiscal basis.

INPUTS FOR THE LARGE INDUSTRIAL SALES FORECAST

Year	Month	Large Industrial Sales (mWh)	Real Per Capita Personal Income (2005 $)	Real Average Price for Industrial- 24 month average (cent/kWh)	CPI (1982-1984 =100)	Dummy October 2004	Out-of-Model Intercept Adjustment
2001	1	294,039	32.58	2.86	175.60	0	0
2001	2	306,432	32.57	2.86	176.00	0	0
2001	3	294,684	32.53	2.86	176.10	0	0
2001	4	279,919	32.50	2.88	176.40	0	0
2001	5	303,579	32.46	2.91	177.30	0	0
2001	6	286,034	32.43	2.90	177.70	0	0
2001	7	317,529	32.38	2.93	177.40	0	0
2001	8	291,666	32.36	2.97	177.40	0	0
2001	9	295,517	32.37	3.00	178.10	0	0
2001	10	288,855	32.28	3.02	177.60	0	0
2001	11	293,181	32.44	3.03	177.50	0	0
2001	12	298,235	32.61	3.05	177.40	0	0
2002	1	312,196	32.92	3.06	177.70	0	0
2002	2	299,913	32.93	3.08	178.00	0	0
2002	3	282,498	32.85	3.10	178.50	0	0
2002	4	296,200	32.79	3.12	179.30	0	0
2002	5	286,859	32.72	3.13	179.50	0	0
2002	6	309,647	32.68	3.11	179.60	0	0
2002	7	290,999	32.57	3.12	180.00	0	0
2002	8	290,430	32.61	3.12	180.50	0	0
2002	9	291,520	32.64	3.12	180.80	0	0
2002	10	273,510	32.74	3.12	181.20	0	0
2002	11	282,189	32.67	3.12	181.50	0	0
2002	12	299,888	32.58	3.12	181.80	0	0
2003	1	256,884	32.40	3.11	182.60	0	0
2003	2	327,157	32.45	3.10	183.60	0	0
2003	3	309,975	32.55	3.09	183.90	0	0
2003	4	274,115	32.66	3.07	183.20	0	0
2003	5	287,674	32.72	3.06	182.90	0	0
2003	6	295,516	32.76	3.07	183.10	0	0
2003	7	291,239	32.74	3.06	183.70	0	0
2003	8	267,361	32.87	3.05	184.50	0	0
2003	9	301,126	33.03	3.04	185.10	0	0
2003	10	283,262	33.21	3.05	184.90	0	0
2003	11	283,320	33.33	3.06	185.00	0	0
2003	12	290,410	33.44	3.07	185.50	0	0
2004	1	304,128	33.52	3.08	186.30	0	0
2004	2	283,829	33.68	3.08	186.70	0	0
2004	3	277,616	33.84	3.09	187.10	0	0
2004	4	287,666	34.05	3.11	187.40	0	0
2004	5	284,177	34.16	3.12	188.20	0	0
2004	6	270,981	34.26	3.17	188.90	0	0
2004	7	320,550	34.33	3.19	189.10	0	0
2004	8	276,030	34.47	3.21	189.20	0	0
2004	9	271,897	34.61	3.23	189.80	0	0
2004	10	169,107	34.79	3.26	190.80	1	0
2004	11	361,974	34.88	3.27	191.70	0	0
2004	12	330,297	34.93	3.28	191.70	0	0
2005	1	299,271	34.99	3.30	191.60	0	0
2005	2	264,275	35.05	3.33	192.40	0	0
2005	3	280,158	35.13	3.35	193.10	0	0
2005	4	278,451	35.21	3.37	193.70	0	0
2005	5	261,215	35.29	3.38	193.60	0	0
2005	6	272,576	35.37	3.40	193.70	0	0

INPUTS FOR THE LARGE INDUSTRIAL SALES FORECAST

Year	Month	Large Industrial Sales (mWh)	Real Per Capita Personal Income (2005 $)	Real Average Price for Industrial- 24 month average (cent/kWh)	CPI (1982-1984 =100)	Dummy October 2004	Out-of-Model Intercept Adjustment
2005	7	260,099	35.48	3.41	194.90	0	0
2005	8	293,566	35.48	3.42	196.10	0	0
2005	9	250,149	35.49	3.42	198.80	0	0
2005	10	330,085	35.32	3.42	199.10	0	0
2005	11	284,158	35.59	3.41	198.10	0	0
2005	12	287,645	35.94	3.41	198.10	0	0
2006	1	273,360	36.40	3.45	199.30	0	0
2006	2	312,554	36.58	3.49	199.40	0	0
2006	3	275,850	36.66	3.54	199.70	0	0
2006	4	283,304	36.82	3.59	200.70	0	0
2006	5	286,805	36.84	3.63	201.30	0	0
2006	6	328,951	36.87	3.68	201.80	0	0
2006	7	295,072	36.85	3.72	202.90	0	0
2006	8	293,402	36.94	3.77	203.80	0	0
2006	9	282,279	37.04	3.81	202.80	0	0
2006	10	295,575	37.20	3.84	201.90	0	0
2006	11	301,935	37.23	3.89	202.00	0	0
2006	12	272,574	37.22	3.93	203.10	0	0
2007	1	298,853	37.24	3.98	203.38	0	0
2007	2	275,151	37.19	4.00	204.24	0	0
2007	3	277,843	37.14	4.03	205.25	0	0
2007	4	242,846	37.06	4.06	206.01	0	0
2007	5	286,954	37.07	4.08	206.81	0	0
2007	6	278,872	37.09	4.10	207.16	0	0
2007	7	270,910	37.15	4.12	207.66	0	0
2007	8	252,700	37.12	4.15	207.69	0	0
2007	9	275,468	37.07	4.17	208.47	0	0
2007	10	279,560	37.04	4.20	209.16	0	0
2007	11	261,196	36.95	4.22	210.81	0	0
2007	12	250,958	36.89	4.25	211.42	0	0
2008	1	292,705	36.76	4.24	212.18	0	0
2008	2	280,342	36.79	4.21	212.68	0	0
2008	3	247,693	36.82	4.19	213.46	0	0
2008	4	260,759	37.00	4.16	214.12	0	0
2008	5	254,647	36.79	4.14	215.30	0	0
2008	6	283,253	36.55	4.11	217.24	0	0
2008	7	270,608	36.14	4.09	219.13	0	0
2008	8	243,278	36.14	4.08	218.78	0	0
2008	9	261,644	36.21	4.07	218.85	0	0
2008	10	252,781	36.42	4.06	216.93	0	0
2008	11	242,472	36.26	4.06	213.00	0	0
2008	12	256,175	36.03	4.06	211.33	0	0
2009	1	257,038	35.67	4.05	211.90	0	0
2009	2	240,542	35.64	4.06	212.88	0	0
2009	3	224,143	35.67	4.06	212.57	0	0
2009	4	233,237	35.83	4.06	212.80	0	0
2009	5	249,403	35.68	4.07	213.08	0	0
2009	6	249,778	35.45	4.07	214.53	0	0
2009	7	223,347	35.15	4.07	214.78	0	0
2009	8	237,773	35.05	4.07	215.52	0	0
2009	9	240,463	35.02	4.07	215.96	0	0
2009	10	228,402	34.95	4.07	216.45	0	0
2009	11	219,796	34.93	4.08	216.96	0	0
2009	12	258,171	34.91	4.08	217.16	0	0

INPUTS FOR THE LARGE INDUSTRIAL SALES FORECAST

Year	Month	Large Industrial Sales (mWh)	Real Per Capita Personal Income (2005 $)	Real Average Price for Industrial- 24 month average (cent/kWh)	CPI (1982-1984 =100)	Dummy October 2004	Out-of-Model Intercept Adjustment
2010	1	236,893	34.81	3.97	217.46	0	0
2010	2	230,896	34.93	3.94	217.56	0	0
2010	3	208,344	35.06	3.92	217.61	0	0
2010	4	232,564	35.28	3.90	217.63	0	0
2010	5	235,617	35.31	3.87	217.32	0	0
2010	6	245,881	35.28	3.85	216.87	0	0
2010	7	234,817	35.26	3.83	217.62	0	0
2010	8	237,072	35.25	3.80	218.07	0	0
2010	9	236,615	35.26	3.76	218.43	0	0
2010	10	222,750	35.24	3.73	218.97	0	0
2010	11	229,900	35.29	3.68	219.24	0	0
2010	12	228,581	35.35	3.64	220.19	0	0
2011	1	220,459	35.43	3.60	221.06	0	0
2011	2	218,087	35.45	3.56	222.27	0	0
2011	3	219,574	35.46	3.53	223.49	0	0
2011	4	248,653	35.43	3.49	224.43	0	0
2011	5	227,788	35.48	3.46	224.80	0	0
2011	6	251,289	35.56	3.42	224.30	0	0
2011	7	229,185	35.63	3.39	225.43	0	0
2011	8	240,246	35.70	3.36	225.07	0	0
2011	9	237,226	35.75	3.34	225.45	0	3,981
2011	10	238,363	35.86	3.32	225.66	0	4,000
2011	11	237,964	35.83	3.29	225.84	0	3,993
2011	12	237,387	35.79	3.26	226.03	0	3,983
2012	1	233,941	35.69	3.36	226.65	0	3,926
2012	2	233,348	35.72	3.37	227.05	0	3,916
2012	3	233,119	35.78	3.37	227.46	0	3,912
2012	4	233,271	35.84	3.38	227.66	0	3,914
2012	5	233,259	35.88	3.39	227.86	0	3,914
2012	6	233,074	35.91	3.40	228.07	0	3,911
2012	7	231,931	35.94	3.41	228.75	0	3,892
2012	8	231,293	35.98	3.42	229.24	0	3,881
2012	9	230,669	36.02	3.43	229.73	0	3,871
2012	10	230,685	36.08	3.44	230.00	0	3,871
2012	11	230,087	36.10	3.44	230.36	0	3,861
2012	12	229,469	36.11	3.45	230.72	0	3,851
2013	1	228,509	36.10	3.45	231.15	0	3,834
2013	2	228,204	36.15	3.45	231.54	0	3,829
2013	3	228,065	36.20	3.45	231.93	0	3,827
2013	4	227,797	36.25	3.45	232.33	0	3,823
2013	5	227,704	36.31	3.45	232.72	0	3,821
2013	6	227,468	36.37	3.46	233.11	0	3,817
2013	7	227,459	36.44	3.46	233.49	0	3,817
2013	8	227,130	36.47	3.45	233.86	0	3,811
2013	9	226,872	36.50	3.44	234.23	0	3,807
2013	10	225,801	36.48	3.44	234.68	0	3,789
2013	11	226,311	36.59	3.43	235.10	0	3,798
2013	12	227,075	36.73	3.42	235.52	0	3,810

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
1990	1	2,789,309	12,840,486	0
1990	2	2,801,736	12,873,014	0
1990	3	2,810,457	12,905,543	0
1990	4	2,805,566	12,938,071	0
1990	5	2,785,369	12,964,793	0
1990	6	2,780,977	12,991,515	0
1990	7	2,783,339	13,018,236	0
1990	8	2,787,017	13,044,958	0
1990	9	2,794,558	13,071,680	0
1990	10	2,803,417	13,098,402	0
1990	11	2,825,310	13,125,123	0
1990	12	2,847,451	13,151,845	0
1991	1	2,863,612	13,178,567	0
1991	2	2,873,938	13,205,289	0
1991	3	2,881,526	13,232,010	0
1991	4	2,871,191	13,258,732	0
1991	5	2,850,529	13,278,633	0
1991	6	2,844,161	13,298,534	0
1991	7	2,843,789	13,318,434	0
1991	8	2,846,483	13,338,335	0
1991	9	2,850,191	13,358,236	0
1991	10	2,857,859	13,378,137	0
1991	11	2,878,308	13,398,037	0
1991	12	2,896,783	13,417,938	0
1992	1	2,912,885	13,437,839	0
1992	2	2,923,007	13,457,740	0
1992	3	2,928,941	13,477,640	0
1992	4	2,920,001	13,497,541	0
1992	5	2,897,947	13,516,922	0
1992	6	2,892,243	13,536,303	0
1992	7	2,894,196	13,555,685	0
1992	8	2,898,600	13,575,066	0
1992	9	2,900,139	13,594,447	0
1992	10	2,904,309	13,613,828	0
1992	11	2,925,526	13,633,209	0
1992	12	2,943,890	13,652,590	0
1993	1	2,958,573	13,671,972	0
1993	2	2,970,571	13,691,353	0
1993	3	2,977,770	13,710,734	0
1993	4	2,972,519	13,730,115	0
1993	5	2,967,267	13,756,252	0
1993	6	2,957,190	13,782,389	0
1993	7	2,961,143	13,808,526	0
1993	8	2,968,272	13,834,662	0
1993	9	2,970,527	13,860,799	0
1993	10	2,975,728	13,886,936	0
1993	11	2,996,373	13,913,073	0
1993	12	3,013,112	13,939,210	0
1994	1	3,027,857	13,965,347	0
1994	2	3,038,702	13,991,483	0
1994	3	3,046,388	14,017,620	0

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
1994	4	3,043,543	14,043,757	0
1994	5	3,028,412	14,068,110	0
1994	6	3,020,716	14,092,463	0
1994	7	3,018,690	14,116,816	0
1994	8	3,026,580	14,141,169	0
1994	9	3,030,160	14,165,522	0
1994	10	3,036,364	14,189,875	0
1994	11	3,057,775	14,214,227	0
1994	12	3,076,365	14,238,580	0
1995	1	3,091,289	14,262,933	0
1995	2	3,100,476	14,287,286	0
1995	3	3,105,323	14,311,639	0
1995	4	3,099,816	14,335,992	0
1995	5	3,085,128	14,359,944	0
1995	6	3,082,695	14,383,897	0
1995	7	3,082,700	14,407,849	0
1995	8	3,085,507	14,431,802	0
1995	9	3,091,480	14,455,754	0
1995	10	3,098,011	14,479,707	0
1995	11	3,114,036	14,503,659	0
1995	12	3,129,838	14,527,611	0
1996	1	3,147,199	14,551,564	0
1996	2	3,154,142	14,575,516	0
1996	3	3,158,499	14,599,469	0
1996	4	3,157,765	14,623,421	0
1996	5	3,143,915	14,649,662	0
1996	6	3,140,094	14,675,903	0
1996	7	3,140,301	14,702,144	0
1996	8	3,143,491	14,728,385	0
1996	9	3,146,569	14,754,626	0
1996	10	3,151,602	14,780,868	0
1996	11	3,165,144	14,807,109	0
1996	12	3,182,783	14,833,350	0
1997	1	3,196,886	14,859,591	0
1997	2	3,206,611	14,885,832	0
1997	3	3,214,954	14,912,073	0
1997	4	3,212,409	14,938,314	0
1997	5	3,198,836	14,962,656	0
1997	6	3,194,640	14,986,999	0
1997	7	3,198,490	15,011,341	0
1997	8	3,202,409	15,035,683	0
1997	9	3,209,319	15,060,025	0
1997	10	3,213,236	15,084,368	0
1997	11	3,224,383	15,108,710	0
1997	12	3,239,398	15,133,052	0
1998	1	3,248,999	15,157,394	0
1998	2	3,259,277	15,181,737	0
1998	3	3,266,915	15,206,079	0
1998	4	3,267,541	15,230,421	0
1998	5	3,256,075	15,259,573	0
1998	6	3,256,616	15,288,725	0

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
1998	7	3,261,244	15,317,877	0
1998	8	3,262,709	15,347,029	0
1998	9	3,266,548	15,376,181	0
1998	10	3,269,554	15,405,333	0
1998	11	3,281,826	15,434,484	0
1998	12	3,294,826	15,463,636	0
1999	1	3,309,816	15,492,788	0
1999	2	3,319,728	15,521,940	0
1999	3	3,329,454	15,551,092	0
1999	4	3,329,366	15,580,244	0
1999	5	3,321,534	15,613,792	0
1999	6	3,321,366	15,647,341	0
1999	7	3,323,325	15,680,889	0
1999	8	3,329,527	15,714,437	0
1999	9	3,336,447	15,747,986	0
1999	10	3,342,147	15,781,534	0
1999	11	3,354,917	15,815,082	0
1999	12	3,371,437	15,848,631	0
2000	1	3,384,081	15,882,179	0
2000	2	3,397,197	15,915,727	0
2000	3	3,407,888	15,949,276	0
2000	4	3,411,552	15,982,824	0
2000	5	3,404,302	16,009,680	0
2000	6	3,404,846	16,036,537	0
2000	7	3,407,511	16,063,393	0
2000	8	3,414,648	16,090,249	0
2000	9	3,420,410	16,117,106	0
2000	10	3,426,807	16,143,962	0
2000	11	3,437,316	16,170,818	0
2000	12	3,450,872	16,197,675	0
2001	1	3,466,059	16,224,531	0
2001	2	3,476,162	16,251,387	0
2001	3	3,485,376	16,278,244	0
2001	4	3,490,194	16,305,100	0
2001	5	3,483,167	16,332,530	0
2001	6	3,481,488	16,359,959	0
2001	7	3,486,754	16,387,389	0
2001	8	3,492,135	16,414,819	0
2001	9	3,495,624	16,442,248	0
2001	10	3,500,574	16,469,678	0
2001	11	3,507,818	16,497,108	0
2001	12	3,521,146	16,524,537	0
2002	1	3,530,913	16,551,967	0
2002	2	3,544,032	16,579,397	0
2002	3	3,554,186	16,606,826	0
2002	4	3,560,727	16,634,256	0
2002	5	3,557,221	16,663,044	0
2002	6	3,557,800	16,691,831	0
2002	7	3,562,956	16,720,619	0
2002	8	3,569,998	16,749,406	0
2002	9	3,574,767	16,778,194	0

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
2002	10	3,582,615	16,806,981	0
2002	11	3,593,622	16,835,769	0
2002	12	3,605,161	16,864,556	0
2003	1	3,613,511	16,893,344	0
2003	2	3,626,512	16,922,131	0
2003	3	3,637,857	16,950,919	0
2003	4	3,645,127	16,979,706	0
2003	5	3,642,135	17,012,633	0
2003	6	3,646,035	17,045,559	0
2003	7	3,649,435	17,078,486	0
2003	8	3,655,348	17,111,412	0
2003	9	3,663,254	17,144,339	0
2003	10	3,672,105	17,177,265	0
2003	11	3,684,389	17,210,192	0
2003	12	3,696,253	17,243,118	0
2004	1	3,704,268	17,276,045	0
2004	2	3,718,571	17,308,971	0
2004	3	3,731,504	17,341,898	0
2004	4	3,740,091	17,374,824	0
2004	5	3,740,143	17,408,435	0
2004	6	3,744,897	17,442,046	0
2004	7	3,752,041	17,475,657	0
2004	8	3,758,762	17,509,268	0
2004	9	3,755,791	17,542,879	0
2004	10	3,751,167	17,576,490	0
2004	11	3,768,160	17,610,101	0
2004	12	3,773,579	17,643,712	0
2005	1	3,786,666	17,677,323	0
2005	2	3,800,127	17,710,934	0
2005	3	3,810,317	17,744,545	0
2005	4	3,819,071	17,778,156	0
2005	5	3,820,847	17,809,516	0
2005	6	3,826,539	17,840,876	0
2005	7	3,832,397	17,872,236	0
2005	8	3,843,228	17,903,596	0
2005	9	3,845,823	17,934,956	0
2005	10	3,846,999	17,966,316	0
2005	11	3,849,102	17,997,675	0
2005	12	3,859,377	18,029,035	0
2006	1	3,872,326	18,060,395	0
2006	2	3,879,506	18,091,755	0
2006	3	3,890,134	18,123,115	0
2006	4	3,898,256	18,154,475	0
2006	5	3,895,260	18,178,833	0
2006	6	3,900,600	18,203,191	0
2006	7	3,902,901	18,227,548	0
2006	8	3,911,165	18,251,906	0
2006	9	3,918,631	18,276,264	0
2006	10	3,923,143	18,300,622	0
2006	11	3,935,484	18,324,979	0
2006	12	3,947,802	18,349,337	0

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
2007	1	3,955,335	18,373,695	0
2007	2	3,965,136	18,398,053	0
2007	3	3,975,438	18,422,410	0
2007	4	3,979,792	18,446,768	0
2007	5	3,978,583	18,460,696	0
2007	6	3,981,256	18,474,624	0
2007	7	3,986,068	18,488,552	0
2007	8	3,991,803	18,502,480	0
2007	9	3,990,293	18,516,408	0
2007	10	3,990,563	18,530,337	0
2007	11	3,990,843	18,544,265	0
2007	12	3,992,297	18,558,193	0
2008	1	3,995,414	18,572,121	0
2008	2	4,001,651	18,586,049	0
2008	3	4,003,023	18,599,977	0
2008	4	4,001,785	18,613,905	0
2008	5	3,996,910	18,620,032	0
2008	6	3,996,829	18,626,158	0
2008	7	3,991,810	18,632,285	0
2008	8	3,989,187	18,638,412	0
2008	9	3,985,030	18,644,538	0
2008	10	3,983,523	18,650,665	0
2008	11	3,981,138	18,656,792	0
2008	12	3,980,785	18,662,918	0
2009	1	3,981,732	18,669,045	0
2009	2	3,986,717	18,675,172	0
2009	3	3,987,693	18,681,298	0
2009	4	3,987,872	18,687,425	0
2009	5	3,984,699	18,696,915	0
2009	6	3,984,326	18,706,406	0
2009	7	3,984,488	18,715,896	0
2009	8	3,984,668	18,725,387	0
2009	9	3,981,876	18,734,877	0
2009	10	3,980,940	18,744,368	0
2009	11	3,984,445	18,753,858	0
2009	12	3,984,423	18,763,348	0
2010	1	3,988,092	18,772,839	0
2010	2	3,996,803	18,782,329	0
2010	3	4,002,154	18,791,820	0
2010	4	4,005,428	18,801,310	0
2010	5	4,006,527	18,809,936	0
2010	6	4,006,189	18,818,561	0
2010	7	4,006,320	18,827,187	0
2010	8	4,009,524	18,835,813	0
2010	9	4,007,495	18,844,438	0
2010	10	4,006,475	18,853,064	0
2010	11	4,007,538	18,861,690	0
2010	12	4,009,847	18,870,315	0
2011	1	4,015,002	18,878,941	0
2011	2	4,021,384	18,887,567	0
2011	3	4,027,937	18,896,192	0

INPUTS FOR THE RESIDENTIAL CUSTOMER FORECAST

Year	Month	Residential Customer	Florida Population	Out-of-Model Adjustment for Reconciliation to Total Customers
2011	4	4,030,950	18,904,818	0
2011	5	4,029,779	18,913,526	0
2011	6	4,028,663	18,922,234	0
2011	7	4,028,593	18,930,942	0
2011	8	4,028,230	18,939,650	-4,140
2011	9	4,028,460	18,948,358	-2,653
2011	10	4,027,450	18,957,066	-3,248
2011	11	4,028,014	18,965,774	-4,013
2011	12	4,029,343	18,974,482	-5,056
2012	1	4,033,938	18,983,190	-5,218
2012	2	4,038,849	18,991,898	-6,090
2012	3	4,044,450	19,000,606	-6,411
2012	4	4,047,186	19,009,314	-6,622
2012	5	4,047,623	19,022,315	-6,575
2012	6	4,048,010	19,035,317	-6,620
2012	7	4,049,776	19,048,318	-6,696
2012	8	4,053,623	19,061,319	-6,849
2012	9	4,053,543	19,074,320	-7,233
2012	10	4,054,086	19,087,322	-7,699
2012	11	4,055,945	19,100,323	-8,311
2012	12	4,058,455	19,113,324	-9,144
2013	1	4,063,668	19,126,325	-9,274
2013	2	4,069,091	19,139,327	-10,053
2013	3	4,075,032	19,152,328	-10,429
2013	4	4,078,626	19,165,329	-10,652
2013	5	4,080,871	19,184,025	-10,548
2013	6	4,083,093	19,202,721	-10,503
2013	7	4,086,436	19,221,417	-10,516
2013	8	4,091,499	19,240,113	-10,620
2013	9	4,093,361	19,258,809	-10,821
2013	10	4,095,741	19,277,506	-11,095
2013	11	4,099,186	19,296,202	-11,527
2013	12	4,103,159	19,314,898	-12,164

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment (000's)
1990	1	333,217	5,362
1990	2	334,142	5,372
1990	3	335,181	5,377
1990	4	336,137	5,390
1990	5	336,651	5,388
1990	6	337,304	5,384
1990	7	337,581	5,383
1990	8	338,021	5,377
1990	9	338,209	5,371
1990	10	338,748	5,370
1990	11	339,791	5,355
1990	12	340,611	5,338
1991	1	340,912	5,318
1991	2	341,101	5,305
1991	3	341,797	5,297
1991	4	342,594	5,281
1991	5	343,104	5,280
1991	6	343,640	5,280
1991	7	344,117	5,280
1991	8	344,526	5,277
1991	9	344,985	5,275
1991	10	345,469	5,266
1991	11	346,486	5,274
1991	12	347,275	5,285
1992	1	347,496	5,297
1992	2	348,069	5,304
1992	3	348,817	5,309
1992	4	349,305	5,313
1992	5	350,122	5,320
1992	6	350,639	5,329
1992	7	350,922	5,332
1992	8	350,634	5,350
1992	9	350,866	5,370
1992	10	351,419	5,390
1992	11	352,159	5,411
1992	12	352,784	5,432
1993	1	353,366	5,451
1993	2	354,218	5,475
1993	3	354,743	5,499
1993	4	357,258	5,529
1993	5	359,772	5,544
1993	6	359,223	5,557
1993	7	359,426	5,567
1993	8	360,459	5,583
1993	9	361,037	5,602
1993	10	360,854	5,619
1993	11	361,579	5,638
1993	12	362,117	5,657
1994	1	362,728	5,675
1994	2	363,288	5,696
1994	3	364,383	5,718
1994	4	365,207	5,742

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment
1994	5	365,964	5,762
1994	6	366,357	5,780
1994	7	366,291	5,799
1994	8	367,264	5,818
1994	9	367,773	5,837
1994	10	368,314	5,858
1994	11	369,301	5,875
1994	12	370,041	5,892
1995	1	370,371	5,910
1995	2	371,337	5,924
1995	3	372,052	5,938
1995	4	372,421	5,955
1995	5	373,216	5,964
1995	6	373,898	5,974
1995	7	374,339	5,976
1995	8	374,848	5,995
1995	9	375,519	6,017
1995	10	376,141	6,041
1995	11	376,737	6,060
1995	12	377,184	6,076
1996	1	378,338	6,094
1996	2	378,061	6,107
1996	3	378,733	6,120
1996	4	379,637	6,132
1996	5	380,394	6,144
1996	6	380,645	6,156
1996	7	381,291	6,161
1996	8	381,582	6,184
1996	9	382,020	6,208
1996	10	382,415	6,236
1996	11	383,163	6,255
1996	12	384,039	6,274
1997	1	384,601	6,288
1997	2	385,190	6,313
1997	3	386,421	6,340
1997	4	387,450	6,372
1997	5	388,406	6,391
1997	6	388,496	6,405
1997	7	389,418	6,420
1997	8	390,246	6,436
1997	9	390,872	6,454
1997	10	391,380	6,469
1997	11	391,832	6,492
1997	12	392,554	6,514
1998	1	392,861	6,543
1998	2	394,071	6,558
1998	3	394,774	6,569
1998	4	396,193	6,582
1998	5	395,818	6,591
1998	6	396,605	6,604
1998	7	397,032	6,606
1998	8	397,828	6,632
1998	9	398,361	6,660

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment
1998	10	398,765	6,698
1998	11	399,097	6,712
1998	12	399,587	6,722
1999	1	400,354	6,727
1999	2	401,256	6,747
1999	3	401,912	6,768
1999	4	403,118	6,802
1999	5	404,034	6,804
1999	6	404,536	6,802
1999	7	404,996	6,782
1999	8	406,046	6,805
1999	9	406,998	6,839
1999	10	408,060	6,873
1999	11	408,562	6,902
1999	12	409,431	6,926
2000	1	410,919	6,955
2000	2	411,290	6,974
2000	3	412,265	6,995
2000	4	413,385	7,011
2000	5	414,109	7,039
2000	6	414,878	7,068
2000	7	415,352	7,108
2000	8	416,280	7,123
2000	9	417,493	7,131
2000	10	418,213	7,146
2000	11	419,055	7,149
2000	12	420,276	7,151
2001	1	421,718	7,153
2001	2	423,096	7,154
2001	3	423,639	7,156
2001	4	424,616	7,154
2001	5	426,058	7,164
2001	6	426,218	7,172
2001	7	427,095	7,194
2001	8	428,133	7,184
2001	9	428,679	7,169
2001	10	429,436	7,147
2001	11	429,714	7,140
2001	12	430,471	7,140
2002	1	430,850	7,132
2002	2	431,813	7,138
2002	3	432,652	7,144
2002	4	433,718	7,149
2002	5	434,426	7,155
2002	6	435,100	7,163
2002	7	435,899	7,168
2002	8	437,275	7,178
2002	9	437,247	7,189
2002	10	437,171	7,204
2002	11	438,362	7,210
2002	12	439,245	7,214
2003	1	439,718	7,220
2003	2	440,526	7,220

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment
2003	3	441,273	7,222
2003	4	442,374	7,218
2003	5	443,371	7,226
2003	6	443,371	7,237
2003	7	445,030	7,246
2003	8	445,870	7,256
2003	9	446,934	7,267
2003	10	448,097	7,267
2003	11	449,181	7,294
2003	12	450,059	7,326
2004	1	452,810	7,359
2004	2	452,608	7,390
2004	3	453,610	7,418
2004	4	455,366	7,454
2004	5	456,743	7,471
2004	6	458,187	7,487
2004	7	459,730	7,495
2004	8	461,098	7,522
2004	9	461,333	7,553
2004	10	461,119	7,587
2004	11	461,982	7,612
2004	12	462,054	7,634
2005	1	463,480	7,654
2005	2	465,109	7,677
2005	3	466,575	7,704
2005	4	467,914	7,723
2005	5	469,571	7,759
2005	6	470,491	7,794
2005	7	471,476	7,843
2005	8	472,697	7,862
2005	9	473,026	7,874
2005	10	473,428	7,888
2005	11	472,696	7,901
2005	12	473,207	7,915
2006	1	473,930	7,927
2006	2	474,305	7,944
2006	3	475,672	7,961
2006	4	475,672	7,981
2006	5	477,188	7,995
2006	6	478,167	8,008
2006	7	478,917	8,025
2006	8	480,159	8,031
2006	9	481,898	8,036
2006	10	482,394	8,039
2006	11	483,417	8,045
2006	12	484,690	8,052
2007	1	485,923	8,063
2007	2	487,244	8,064
2007	3	488,828	8,060
2007	4	490,015	8,065
2007	5	492,421	8,050
2007	6	493,770	8,033
2007	7	494,995	8,015

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment
2007	8	495,345	8,001
2007	9	496,714	7,989
2007	10	497,020	7,980
2007	11	497,534	7,964
2007	12	497,756	7,945
2008	1	498,674	7,936
2008	2	499,460	7,903
2008	3	499,080	7,867
2008	4	499,289	7,830
2008	5	500,326	7,795
2008	6	500,723	7,760
2008	7	501,265	7,730
2008	8	501,848	7,691
2008	9	501,941	7,647
2008	10	502,471	7,614
2008	11	502,192	7,556
2008	12	501,710	7,497
2009	1	501,254	7,426
2009	2	501,487	7,380
2009	3	501,087	7,342
2009	4	500,729	7,294
2009	5	500,715	7,265
2009	6	500,178	7,240
2009	7	500,612	7,204
2009	8	501,173	7,191
2009	9	501,060	7,183
2009	10	501,374	7,173
2009	11	501,505	7,164
2009	12	501,482	7,159
2010	1	501,516	7,140
2010	2	501,369	7,153
2010	3	502,122	7,169
2010	4	502,350	7,197
2010	5	502,833	7,197
2010	6	503,340	7,191
2010	7	504,091	7,184
2010	8	504,878	7,181
2010	9	504,956	7,181
2010	10	504,974	7,181
2010	11	505,065	7,178
2010	12	504,858	7,177
2011	1	505,744	7,163
2011	2	505,721	7,180
2011	3	506,421	7,203
2011	4	507,047	7,233
2011	5	507,722	7,243
2011	6	508,402	7,249
2011	7	508,810	7,253
2011	8	509,838	7,262
2011	9	510,604	7,273
2011	10	511,354	7,283
2011	11	512,132	7,296
2011	12	512,905	7,309

INPUTS FOR THE COMMERCIAL CUSTOMER FORECAST

Year	Month	Commercial Customer	FL Non-Agricultural Employment
2012	1	513,690	7,323
2012	2	514,451	7,334
2012	3	515,210	7,344
2012	4	515,965	7,355
2012	5	516,730	7,366
2012	6	517,500	7,378
2012	7	518,267	7,389
2012	8	519,041	7,402
2012	9	519,813	7,414
2012	10	520,594	7,427
2012	11	521,353	7,437
2012	12	522,112	7,448
2013	1	522,853	7,456
2013	2	523,636	7,469
2013	3	524,432	7,483
2013	4	525,217	7,496
2013	5	526,025	7,512
2013	6	526,833	7,528
2013	7	527,650	7,545
2013	8	528,449	7,559
2013	9	529,244	7,573
2013	10	530,043	7,588
2013	11	530,836	7,602
2013	12	531,630	7,616

INPUTS FOR THE SMALL INDUSTRIAL CUSTOMER FORECAST

Year	Month	Small Industrial Customers	Florida Housing Starts Lagged One Month (000's)	Employment Lagged One Month (000's)
1995	1	13,280	135.01	5,891.51
1995	2	13,124	127.91	5,909.53
1995	3	12,865	123.86	5,924.43
1995	4	12,618	121.93	5,938.04
1995	5	12,483	115.37	5,954.62
1995	6	12,524	119.04	5,963.92
1995	7	12,521	123.79	5,973.56
1995	8	12,342	131.18	5,976.21
1995	9	12,328	131.95	5,995.13
1995	10	12,288	131.02	6,017.27
1995	11	12,242	129.57	6,041.44
1995	12	12,199	130.04	6,059.96
1996	1	12,173	131.40	6,075.60
1996	2	12,019	132.89	6,094.23
1996	3	12,093	133.56	6,107.30
1996	4	12,148	134.04	6,119.67
1996	5	12,127	133.58	6,132.46
1996	6	12,131	135.68	6,143.55
1996	7	12,269	137.91	6,156.19
1996	8	12,352	142.63	6,161.48
1996	9	12,474	141.70	6,183.59
1996	10	12,553	139.12	6,208.33
1996	11	12,488	137.07	6,235.60
1996	12	12,564	133.60	6,255.34
1997	1	12,411	131.80	6,273.66
1997	2	12,254	124.11	6,287.86
1997	3	12,220	130.17	6,312.89
1997	4	12,124	137.49	6,339.56
1997	5	12,133	150.57	6,371.90
1997	6	12,221	149.41	6,390.51
1997	7	12,358	145.29	6,405.39
1997	8	12,390	138.65	6,420.22
1997	9	12,570	139.39	6,436.12
1997	10	12,586	142.09	6,454.37
1997	11	12,588	147.20	6,469.01
1997	12	12,527	145.64	6,491.82
1998	1	12,517	142.51	6,514.47
1998	2	12,501	136.70	6,543.37
1998	3	12,541	137.50	6,558.22
1998	4	12,450	140.66	6,569.30
1998	5	12,483	142.54	6,581.65
1998	6	12,516	146.87	6,591.07
1998	7	12,809	150.27	6,603.57
1998	8	12,971	156.04	6,605.73
1998	9	13,089	155.67	6,631.92
1998	10	13,176	155.94	6,660.35
1998	11	13,292	150.20	6,698.14
1998	12	13,407	159.98	6,712.48
1999	1	13,405	169.88	6,722.28
1999	2	13,341	193.03	6,727.40
1999	3	13,420	184.36	6,747.10
1999	4	13,448	170.30	6,768.20

INPUTS FOR THE SMALL INDUSTRIAL CUSTOMER FORECAST

Year	Month	Small Industrial Customers	Florida Housing Starts Lagged One Month	Employment Lagged One Month
1999	5	13,646	147.96	6,801.73
1999	6	13,803	147.09	6,803.63
1999	7	13,950	152.53	6,801.84
1999	8	14,169	158.57	6,782.45
1999	9	14,215	160.36	6,805.28
1999	10	14,081	159.78	6,838.88
1999	11	14,011	157.41	6,872.83
1999	12	13,969	160.62	6,902.28
2000	1	13,931	164.99	6,926.30
2000	2	13,973	173.38	6,954.59
2000	3	14,177	172.38	6,974.36
2000	4	14,149	168.24	6,995.25
2000	5	14,150	166.31	7,011.07
2000	6	14,242	159.83	7,039.47
2000	7	14,342	154.46	7,068.16
2000	8	14,317	143.63	7,107.60
2000	9	14,334	144.94	7,122.86
2000	10	14,272	148.80	7,131.14
2000	11	14,132	152.19	7,145.88
2000	12	13,988	155.74	7,148.62
2001	1	13,761	158.38	7,150.50
2001	2	13,543	161.74	7,152.70
2001	3	13,293	163.75	7,153.70
2001	4	13,380	165.83	7,156.10
2001	5	13,307	168.21	7,154.10
2001	6	13,226	170.58	7,163.57
2001	7	13,275	171.69	7,172.03
2001	8	13,149	176.85	7,194.25
2001	9	13,033	171.64	7,184.42
2001	10	13,092	167.05	7,168.63
2001	11	13,117	152.11	7,147.47
2001	12	13,099	162.17	7,140.33
2002	1	13,053	175.54	7,139.60
2002	2	13,158	198.60	7,132.41
2002	3	13,152	197.84	7,137.50
2002	4	13,023	190.74	7,143.59
2002	5	13,159	183.09	7,148.67
2002	6	13,263	178.99	7,155.30
2002	7	12,885	178.07	7,162.63
2002	8	12,978	174.81	7,167.54
2002	9	13,755	175.43	7,178.22
2002	10	14,057	176.43	7,189.24
2002	11	14,153	175.46	7,204.10
2002	12	14,270	179.06	7,210.32
2003	1	14,127	183.31	7,213.77
2003	2	14,254	188.68	7,219.68
2003	3	14,494	191.18	7,220.32
2003	4	14,558	192.87	7,221.80
2003	5	14,703	193.80	7,217.99
2003	6	14,910	196.30	7,226.10
2003	7	14,972	200.32	7,236.62
2003	8	15,159	200.88	7,245.77
2003	9	15,266	209.54	7,255.58

INPUTS FOR THE SMALL INDUSTRIAL CUSTOMER FORECAST

Year	Month	Small Industrial Customers	Florida Housing Starts Lagged One Month	Employment Lagged One Month
2003	10	15,508	218.38	7,267.45
2003	11	15,737	232.39	7,267.28
2003	12	15,748	234.16	7,293.96
2004	1	15,680	233.42	7,326.46
2004	2	15,726	231.64	7,358.74
2004	3	15,911	233.66	7,390.41
2004	4	16,216	236.67	7,418.05
2004	5	16,230	242.28	7,454.18
2004	6	16,398	241.20	7,471.19
2004	7	16,936	238.79	7,486.93
2004	8	17,354	233.95	7,494.81
2004	9	17,095	235.05	7,521.84
2004	10	17,044	238.28	7,552.85
2004	11	16,593	239.56	7,587.31
2004	12	16,185	244.28	7,612.21
2005	1	17,107	249.54	7,633.68
2005	2	17,539	253.93	7,654.28
2005	3	17,754	260.99	7,677.18
2005	4	17,974	266.97	7,703.54
2005	5	18,351	279.03	7,722.94
2005	6	18,647	276.72	7,758.67
2005	7	18,690	272.70	7,794.29
2005	8	19,142	263.39	7,842.55
2005	9	18,999	267.23	7,861.88
2005	10	19,011	274.24	7,874.17
2005	11	18,699	284.53	7,888.40
2005	12	17,892	287.63	7,900.64
2006	1	17,711	285.20	7,915.16
2006	2	18,876	295.46	7,927.27
2006	3	19,023	278.11	7,944.25
2006	4	19,086	256.97	7,961.28
2006	5	19,496	232.18	7,980.65
2006	6	19,587	217.32	7,995.31
2006	7	19,414	205.93	8,007.64
2006	8	19,525	193.99	8,025.44
2006	9	19,430	181.70	8,031.35
2006	10	19,172	168.70	8,035.51
2006	11	19,271	153.32	8,039.09
2006	12	19,424	143.19	8,045.23
2007	1	19,205	135.39	8,051.58
2007	2	19,191	123.65	8,063.15
2007	3	18,863	120.30	8,063.79
2007	4	18,238	117.78	8,059.76
2007	5	17,805	116.86	8,064.94
2007	6	17,111	111.90	8,050.45
2007	7	16,416	105.79	8,033.31
2007	8	15,808	99.38	8,014.55
2007	9	15,407	93.91	8,000.84
2007	10	14,895	89.38	7,988.72
2007	11	14,344	83.16	7,979.66
2007	12	13,750	80.49	7,964.30
2008	1	13,210	78.32	7,944.54
2008	2	12,770	76.33	7,935.89

INPUTS FOR THE SMALL INDUSTRIAL CUSTOMER FORECAST

Year	Month	Small Industrial Customers	Florida Housing Starts Lagged One Month	Employment Lagged One Month
2008	3	12,308	73.76	7,903.32
2008	4	12,024	70.81	7,866.59
2008	5	11,713	68.17	7,830.44
2008	6	11,518	64.85	7,794.96
2008	7	11,308	61.69	7,760.30
2008	8	11,079	57.81	7,729.90
2008	9	10,956	55.73	7,690.88
2008	10	10,723	53.69	7,646.92
2008	11	10,448	52.98	7,613.95
2008	12	10,111	49.06	7,556.31
2009	1	9,604	44.58	7,496.65
2009	2	9,269	39.00	7,426.48
2009	3	9,017	35.89	7,380.32
2009	4	8,693	34.02	7,342.20
2009	5	8,514	29.95	7,293.81
2009	6	8,254	30.57	7,264.55
2009	7	8,132	31.73	7,239.64
2009	8	7,973	33.30	7,203.73
2009	9	7,855	33.52	7,191.43
2009	10	7,778	33.59	7,183.34
2009	11	7,703	32.33	7,172.52
2009	12	7,561	34.36	7,164.38
2010	1	7,383	36.96	7,158.90
2010	2	7,353	40.73	7,139.92
2010	3	7,302	41.65	7,152.56
2010	4	7,314	41.57	7,169.13
2010	5	7,236	42.46	7,196.56
2010	6	7,263	41.65	7,197.14
2010	7	7,255	40.50	7,190.60
2010	8	7,238	39.98	7,183.51
2010	9	7,344	37.61	7,180.78
2010	10	7,424	35.80	7,180.81
2010	11	7,307	30.49	7,180.62
2010	12	7,177	33.48	7,177.94
2011	1	7,143	37.44	7,177.15
2011	2	7,145	44.45	7,162.58
2011	3	7,084	43.75	7,180.11
2011	4	7,136	41.43	7,202.71
2011	5	7,192	37.21	7,232.57
2011	6	7,161	38.05	7,243.48
2011	7	7,148	40.53	7,248.72
2011	8	7,136	43.03	7,252.93
2011	9	7,140	44.82	7,261.56
2011	10	7,157	45.94	7,273.35
2011	11	7,165	47.15	7,283.33
2011	12	7,188	48.42	7,296.38
2012	1	7,209	49.89	7,308.88
2012	2	7,235	51.25	7,322.59
2012	3	7,250	52.60	7,333.66
2012	4	7,264	54.22	7,344.38
2012	5	7,269	54.23	7,354.65
2012	6	7,295	57.70	7,366.04
2012	7	7,327	62.13	7,377.90

INPUTS FOR THE SMALL INDUSTRIAL CUSTOMER FORECAST

Year	Month	Small Industrial Customers	Florida Housing Starts Lagged One Month	Employment Lagged One Month
2012	8	7,353	65.52	7,389.45
2012	9	7,392	71.02	7,401.68
2012	10	7,430	76.56	7,413.65
2012	11	7,475	82.78	7,426.64
2012	12	7,503	87.44	7,437.11
2013	1	7,528	91.71	7,447.53
2013	2	7,545	96.19	7,455.83
2013	3	7,583	100.45	7,468.88
2013	4	7,626	104.59	7,483.35
2013	5	7,668	109.57	7,496.48
2013	6	7,712	112.63	7,512.24
2013	7	7,755	115.30	7,527.98
2013	8	7,802	117.96	7,544.58
2013	9	7,842	120.87	7,559.26
2013	10	7,880	123.82	7,573.40
2013	11	7,922	127.40	7,587.92
2013	12	7,954	129.52	7,601.64

INPUTS FOR THE STREET & HIGHWAY CUSTOMER FORECAST

Year	Month	Street & Highway Customers	Street & Highway Customers Lagged One Month
2000	1	2,341	2,337
2000	2	2,364	2,341
2000	3	2,401	2,364
2000	4	2,414	2,401
2000	5	2,426	2,414
2000	6	2,428	2,426
2000	7	2,428	2,428
2000	8	2,431	2,428
2000	9	2,402	2,431
2000	10	2,408	2,402
2000	11	2,415	2,408
2000	12	2,420	2,415
2001	1	2,408	2,420
2001	2	2,414	2,408
2001	3	2,425	2,414
2001	4	2,437	2,425
2001	5	2,442	2,437
2001	6	2,447	2,442
2001	7	2,451	2,447
2001	8	2,458	2,451
2001	9	2,461	2,458
2001	10	2,469	2,461
2001	11	2,473	2,469
2001	12	2,474	2,473
2002	1	2,478	2,474
2002	2	2,488	2,478
2002	3	2,494	2,488
2002	4	2,508	2,494
2002	5	2,517	2,508
2002	6	2,519	2,517
2002	7	2,528	2,519
2002	8	2,530	2,528
2002	9	2,542	2,530
2002	10	2,546	2,542
2002	11	2,562	2,546
2002	12	2,552	2,562
2003	1	2,563	2,552
2003	2	2,566	2,563
2003	3	2,571	2,566
2003	4	2,575	2,571
2003	5	2,602	2,575
2003	6	2,602	2,602
2003	7	2,633	2,602
2003	8	2,629	2,633
2003	9	2,634	2,629
2003	10	2,638	2,634
2003	11	2,649	2,638
2003	12	2,665	2,649
2004	1	2,676	2,665
2004	2	2,695	2,676
2004	3	2,712	2,695
2004	4	2,733	2,712
2004	5	2,749	2,733

INPUTS FOR THE STREET & HIGHWAY CUSTOMER FORECAST

Year	Month	Street & Highway Customers	Street & Highway Customers Lagged One Month
2004	6	2,767	2,749
2004	7	2,785	2,767
2004	8	2,796	2,785
2004	9	2,802	2,796
2004	10	2,809	2,802
2004	11	2,830	2,809
2004	12	2,846	2,830
2005	1	2,857	2,846
2005	2	2,866	2,857
2005	3	2,869	2,866
2005	4	2,878	2,869
2005	5	2,886	2,878
2005	6	2,892	2,886
2005	7	2,900	2,892
2005	8	2,910	2,900
2005	9	2,916	2,910
2005	10	2,925	2,916
2005	11	2,928	2,925
2005	12	2,938	2,928
2006	1	2,941	2,938
2006	2	2,945	2,941
2006	3	2,944	2,945
2006	4	2,944	2,944
2006	5	2,958	2,944
2006	6	2,967	2,958
2006	7	2,971	2,967
2006	8	2,971	2,971
2006	9	2,967	2,971
2006	10	2,974	2,967
2006	11	2,986	2,974
2006	12	2,990	2,986
2007	1	3,002	2,990
2007	2	3,004	3,002
2007	3	3,010	3,004
2007	4	3,022	3,010
2007	5	3,023	3,022
2007	6	3,027	3,023
2007	7	3,028	3,027
2007	8	3,038	3,028
2007	9	3,052	3,038
2007	10	3,056	3,052
2007	11	3,059	3,056
2007	12	3,064	3,059
2008	1	3,073	3,064
2008	2	3,083	3,073
2008	3	3,095	3,083
2008	4	3,095	3,095
2008	5	3,099	3,095
2008	6	3,107	3,099
2008	7	3,113	3,107
2008	8	3,132	3,113
2008	9	3,141	3,132
2008	10	3,150	3,141

INPUTS FOR THE STREET & HIGHWAY CUSTOMER FORECAST

Year	Month	Street & Highway Customers	Street & Highway Customers Lagged One Month
2008	11	3,155	3,150
2008	12	3,170	3,155
2009	1	3,191	3,170
2009	2	3,202	3,191
2009	3	3,203	3,202
2009	4	3,206	3,203
2009	5	3,212	3,206
2009	6	3,210	3,212
2009	7	3,210	3,210
2009	8	3,214	3,210
2009	9	3,219	3,214
2009	10	3,228	3,219
2009	11	3,247	3,228
2009	12	3,259	3,247
2010	1	3,262	3,259
2010	2	3,275	3,262
2010	3	3,281	3,275
2010	4	3,286	3,281
2010	5	3,291	3,286
2010	6	3,299	3,291
2010	7	3,303	3,299
2010	8	3,305	3,303
2010	9	3,316	3,305
2010	10	3,332	3,316
2010	11	3,346	3,332
2010	12	3,352	3,346
2011	1	3,356	3,352
2011	2	3,361	3,356
2011	3	3,368	3,361
2011	4	3,371	3,368
2011	5	3,368	3,371
2011	6	3,371	3,368
2011	7	3,371	3,371
2011	8	3,385	3,371
2011	9	3,392	3,385
2011	10	3,399	3,392
2011	11	3,406	3,399
2011	12	3,413	3,406
2012	1	3,420	3,413
2012	2	3,427	3,420
2012	3	3,434	3,427
2012	4	3,441	3,434
2012	5	3,448	3,441
2012	6	3,455	3,448
2012	7	3,461	3,455
2012	8	3,468	3,461
2012	9	3,475	3,468
2012	10	3,482	3,475
2012	11	3,489	3,482
2012	12	3,496	3,489
2013	1	3,503	3,496
2013	2	3,510	3,503
2013	3	3,517	3,510

INPUTS FOR THE STREET & HIGHWAY CUSTOMER FORECAST

Year	Month	Street & Highway Customers	Street & Highway Customers Lagged One Month
2013	4	3,523	3,517
2013	5	3,530	3,523
2013	6	3,537	3,530
2013	7	3,544	3,537
2013	8	3,551	3,544
2013	9	3,558	3,551
2013	10	3,564	3,558
2013	11	3,571	3,564
2013	12	3,578	3,571

INPUTS FOR THE SUMMER PEAK FORECAST

Year	System Summer Peak (MW)	Total Average Customers	Energy Efficiency Standards (MW/Customer)	Real per Capita Income weighted by Employed Population (Thousands 2005 $)	Real Price of Electricity Lagged 1 Month ($/kWh)	System Composite Peak Day Maximum Temperature (Fahrenheit)	Cooling Degree Hours Prior Day (Base 72)
1981	9,738	2,285,187	0	8.00	0.0773	95.9	312.9
1982	9,862	2,358,167	0	7.81	0.0648	91.5	263.9
1983	10,676	2,429,688	0	8.19	0.0653	94.9	342.9
1984	10,270	2,520,523	0	8.97	0.0810	91.1	281.6
1985	10,654	2,617,556	0	9.47	0.0779	96.0	272.2
1986	11,022	2,723,555	0	9.85	0.0653	90.3	264.5
1987	12,394	2,840,207	0	10.27	0.0656	92.9	323.5
1988	12,382	2,953,663	0	10.73	0.0665	91.1	275.9
1989	13,425	3,064,436	0	11.26	0.0622	95.0	309.0
1990	13,754	3,158,817	0	11.10	0.0567	95.0	306.0
1991	14,123	3,226,455	0	10.48	0.0547	92.0	286.0
1992	14,661	3,281,238	0	10.47	0.0505	91.0	315.0
1993	15,266	3,355,794	0	10.83	0.0521	91.0	341.0
1994	15,179	3,422,187	0	11.18	0.0459	92.0	248.0
1995	15,813	3,488,796	0	11.63	0.0450	93.0	269.0
1996	16,064	3,550,747	0	12.02	0.0460	90.0	274.0
1997	16,613	3,615,485	0	12.44	0.0465	92.0	288.0
1998	17,897	3,680,470	0	13.25	0.0437	94.0	279.0
1999	17,615	3,756,009	0	13.54	0.0405	91.0	320.0
2000	17,808	3,848,350	0	14.23	0.0410	90.0	287.0
2001	18,754	3,935,281	0	14.20	0.0480	91.3	279.5
2002	19,219	4,019,805	0	14.04	0.0405	91.3	274.3
2003	19,668	4,117,221	0	13.96	0.0426	89.7	291.2
2004	20,545	4,224,509	0	14.73	0.0445	91.9	269.0
2005	22,361	4,321,895	0.01	15.45	0.0457	93.6	334.8
2006	21,819	4,409,563	0.04	16.21	0.0557	91.7	307.3
2007	21,962	4,496,589	0.08	16.10	0.0515	91.9	315.5
2008	21,060	4,509,730	0.17	15.16	0.0494	91.2	299.7
2009	22,351	4,499,067	0.21	13.69	0.0520	95.3	330.0
2010	22,024	4,520,328	0.25	13.42	0.0445	92.8	334.5
2011	21,371	4,543,811	0.30	13.63	0.0442	92.8	316.4
2012	21,623	4,579,174	0.34	13.93	0.0443	91.9	298.7
2013	21,931	4,625,149	0.39	14.27	0.0422	91.9	298.7

Note: Cooling Degree Hours are on a fiscal basis.

INPUTS FOR THE SUMMER PEAK FORECAST

Year	System Summer Peak (MW)	Dummy 1982	Dummy 1990	Dummy 1989	Out-of-Model Adjustment for New/ Modified Wholesale Contracts	Out-of-Model Adjustment for Hybrids	Out-of-Model Adjustment for Economic Development Rate
1981	9,738	0	0	0	0	0	0
1982	9,862	1	0	0	0	0	0
1983	10,676	0	0	0	0	0	0
1984	10,270	0	0	0	0	0	0
1985	10,654	0	0	0	0	0	0
1986	11,022	0	0	0	0	0	0
1987	12,394	0	0	0	0	0	0
1988	12,382	0	0	0	0	0	0
1989	13,425	0	0	1	0	0	0
1990	13,754	0	1	0	0	0	0
1991	14,123	0	0	0	0	0	0
1992	14,661	0	0	0	0	0	0
1993	15,266	0	0	0	0	0	0
1994	15,179	0	0	0	0	0	0
1995	15,813	0	0	0	0	0	0
1996	16,064	0	0	0	0	0	0
1997	16,613	0	0	0	0	0	0
1998	17,897	0	0	0	0	0	0
1999	17,615	0	0	0	0	0	0
2000	17,808	0	0	0	0	0	0
2001	18,754	0	0	0	0	0	0
2002	19,219	0	0	0	0	0	0
2003	19,668	0	0	0	0	0	0
2004	20,545	0	0	0	0	0	0
2005	22,361	0	0	0	0	0	0
2006	21,819	0	0	0	0	0	0
2007	21,962	0	0	0	0	0	0
2008	21,060	0	0	0	0	0	0
2009	22,351	0	0	0	0	0	0
2010	22,024	0	0	0	0	0	0
2011	21,371	0	0	0	0	0	0
2012	21,623	0	0	0	281	2.9	0.0
2013	21,931	0	0	0	237	6.0	12.7

INPUTS FOR THE WINTER PEAK FORECAST

Year	System Winter Peak (MW)	Total Average Customers	System Minimum Temperature on Day of Winter Peak (Fahrenheit)	Heating Degree Hours Squared	Weekend Winter Peak	Out-of-Model Adjustment for Energy Efficiency Standards per customer	Out-of-Model Adjustment for New/ Modified Wholesale contracts	Out-of-Model Adjustment for Hybrids	Out-of-Model Adjustment for Economic Development Rate
1986	12,139	2,723,555	32.7	378,902	0	0	0	0	0
1987	10,779	2,840,207	40.1	276,266	0	0	0	0	0
1988	12,372	2,953,663	42.4	359,580	0	0	0	0	0
1989	12,928	3,064,436	35.3	544,644	1	0	0	0	0
1990	14,125	3,158,817	28.4	622,521	1	0	0	0	0
1991	11,868	3,226,455	38.6	90,000	1	0	0	0	0
1992	13,571	3,281,238	42.7	309,136	0	0	0	0	0
1993	13,647	3,355,794	40.8	362,404	0	0	0	0	0
1994	12,594	3,422,187	48.2	199,809	0	0	0	0	0
1995	16,563	3,488,796	36.0	257,049	0	0	0	0	0
1996	18,567	3,550,747	33.5	447,561	0	0	0	0	0
1997	16,490	3,615,485	35.3	552,049	1	0	0	0	0
1998	13,060	3,680,470	48.2	181,476	0	0	0	0	0
1999	16,802	3,756,009	40.0	458,329	0	0	0	0	0
2000	17,057	3,848,350	38.8	375,769	0	0	0	0	0
2001	19,019	3,935,281	35.8	427,025	0	0	0	0	0
2002	17,597	4,019,805	40.1	395,233	0	0	0	0	0
2003	20,232	4,117,221	33.1	447,561	0	0	0	0	0
2004	14,752	4,224,509	46.7	201,206	0	0	0	0	0
2005	18,108	4,321,895	38.7	139,925	0	0	0	0	0
2006	19,702	4,409,563	38.3	424,057	0	0	0	0	0
2007	16,877	4,496,589	41.6	253,712	0	0	0	0	0
2008	18,304	4,509,730	36.0	428,145	0	0	0	0	0
2009	20,399	4,499,067	34.6	330,556	0	0	0	0	0
2010	24,838	4,520,328	33.4	844,409	0	0	0	0	0
2011	21,890	4,543,811	36.1	664,360	0	0	0	0	0
2012	20,889	4,579,174	36.1	429,529	0	0.11	283	1.14	0
2013	21,101	4,625,149	36.1	429,529	0	0.13	287	2.25	8.46

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended __/__/__
____ Historical Test Year Ended __/__/__

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl, J.A. Stall, Roxane R. Kennedy

Line No. (1) (2) (3) (4) (5) (6) (7) (8) (9)

I. SALES, CUSTOMERS, NET ENERGY FOR LOAD

GENERAL ASSUMPTIONS

	2013
A. Population (Florida)	19,214,917
B. Florida Real Per Capital Income (Base 2005) (000's of Dollars)	36.4
C. Florida Non-Agricultural Employment (000)	7,535.6
D. FPL Service Territory Cooling Degree Hours (Base 72 Degree Temperature)	1,958
E. FPL Service Territory Winter Heating Degree Days (Base 66 Degree Temperature)	265
F. FPL Service Territory Heating Degree Days (Base 45 Degree Temperature)	0.65
G. Weather Sensitive Mandated Energy Efficiency per Customer (MWH)	0.66
H. CPI for Energy	256.0
I. Inactive Ratio	5.42%

J. 2013 Sales by Revenue Class - Most likely (in Million KWH)

Residential	Commercial	Industrial	Street and Highway Lighting	Other	Railroads	Total Retail	Sales for Resale	Total [1]
53,056	46,543	3,021	461	28	93	103,200	2,210	105,411

K. 2013 Customers by Revenue Class

Residential	Commercial	Industrial	Street and Highway Lighting	Other	Railroads	Total Retail	Sales for Resale	Total [1]
4,084,980	527,238	9,174	3,540	187	26	4,625,145	4	4,625,149

L. 2013 Net Change in Customers by Revenue Class

Residential	Commercial	Industrial	Street and Highway Lighting	Other	Railroads	Total Retail	Sales for Resale	Total [2]
36,190	9,344	361	83	-2	0	45,976	-1	45,975

[1] Totals may not add-up due to rounding.
[2] Average 2013 customers - average 2012 customers.

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

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Line No.		(1)	(2)	
1	I.	**M. Most Likely Forecast of Monthly Net Energy for Load (Million KWH)**		
2			<u>2013</u>	
3		**January**	8,409	
4		**February**	7,528	
5		**March**	8,420	
6		**April**	8,574	
7		**May**	9,876	
8		**June**	10,253	
9		**July**	11,167	
10		**August**	11,144	
11		**September**	10,353	
12		**October**	9,769	
13		**November**	8,220	
14		**December**	<u>8,488</u>	
15			112,201	
16				
17		**N. Most Likely Forecast of System Monthly Peaks (Megawatts)**		
18			<u>2013</u>	
19		**January**	21,101	
20		**February**	17,137	
21		**March**	17,137	
22		**April**	17,524	
23		**May**	19,570	
24		**June**	19,851	
25		**July**	20,471	
26		**August**	21,931	
27		**September**	20,347	
28		**October**	19,076	
29		**November**	18,317	
30		**December**	18,332	
31				
32	II.	INFLATION RATE FORECAST		
33		**Most Likely Annual**		
34		**Rates of Change**		
35		**2013**		
36	A.	2.0%		**Consumer Price Index (CPI)**
37				The CPI Measures the price change of a constant market basket of goods and services over time.
38				For company purposes it is a useful escalator for determining trends in wage contracts and income
39				payments, excluding construction work.

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

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Line No. (1) (2) (3)

III. FINANCING AND INTEREST RATE ASSUMPTIONS

General Assumptions

A. Target Capitalization Ratios
During the projected test year, Florida Power & Light Company's investor sources of capitalization is projected to be approximately 59.6% equity and approximately 40.4% debt.

B. Preferred Stock Premium and Underwriting Discount
It is assumed that no preferred stock will be issued.

C. First Mortgage Bond Prices and Underwriting Discount
It is assumed that first mortgage bonds will be issued to the public at par with an underwriting commission of 0.875%.

Interest Rate Assumptions

	2013
D. Long Term Debt	5.1%
Short Term Debt	Although the company maintains several lines of credit, the company forecasts them at zero.
E. Pollution Control Bonds	1.6%
F. Preferred Stock	No preferred stock outstanding.
G. 30-Day Commercial Paper	0.6%

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

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IV. IN SERVICE DATES OF MAJOR PROJECTS

A.

(1) BUDGET ITEM #	(2) PROJECT DESCRIPTION	(3) IN SERVICE DATE*	
	Nuclear Generation Projects		
UNUC00000052	Turkey Point Unit 4 Extended Power Uprate Project**	03/2013	
Various	St Lucie EDG Generator and Radiator Replacement	2013-2015	(Multiple Projects with Various In-Service Dates)
Various	St Lucie Reactor Coolant Pump (RCP) Motor Refurbishments	2013-2016	(Multiple Projects with Various In-Service Dates)
	Steam Generation Projects		
UENC00000048	Manatee ESP U1**	10/2013	
UENC00000050	Martin ESP U1**	07/2014	
UENC00000051	Martin ESP U2**	04/2015	
	Other Generation Projects		
UENC00000004	Cape Canaveral Modernization	06/2013	
UENC00000003	Riviera Modernization	06/2014	
UENC00000065	Port Everglades Modernization	06/2016	
	Transmission Projects		
UENC00000004	Cape Canaveral Modernization-Transmission	06/2013	
UENC00000003	Riviera Modernization-Transmission	06/2014	
	Intangible & General Plant Projects		
UIMS000000198	FENA Phase 2 Project	12/2013	
UCUS000000100	AMI Software	12/2013	
UENC000000025	Corporate Data Center	12/2013	
UTRN000000015	SCC EMS Project	12/2013	

* Projects which have a foreseeable monetary impact in fiscal year 2013.
** Projects which are recovered, or partially recovered, through other mechanisms.

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Line No. (1) (2) (3) (4) (5)

V. MAJOR GENERATING UNIT OUTAGE ASSUMPTIONS

A. Nuclear Maintenance Schedules (Including outage period and reason)

Unit	2013 Outage Period	2013 Outage Description
St. Lucie Unit 1	9/5/2013 - 10/13/2013	Refueling, Extended Power Uprate Project
Turkey Point Unit 3	10/21/2013 - 11/28/2013	Refueling, Steam Generator Eddy Current Testing, 10 year Reactor Vessel Internal Inspection
Turkey Point Unit 4	1/1/2013 - 3/5/2013	Refueling, Extended Power Uprate (Outage begins 11/5/2012)

B. Fossil Units Outage Schedule (Including outage period and reason)

Unit	2013 Outage Start	2013 Outage End	2013 Outage Description
CAPE CANAVERAL 3	11/1/13	11/10/13	3A, 3B, 3C COMBUSTION TURBINE & STEAM TURBINE WARRANTY OUTAGE
FT. MYERS 2	10/5/13	12/6/13	HP/IP STEAM TURBINE, STEAM TURBINE GENERATOR, P91
FT. MYERS 2	10/5/13	10/11/13	A HRSG INSPECTION
FT. MYERS 2	10/5/13	10/11/13	B HRSG INSPECTION
FT. MYERS 2	10/12/13	10/18/13	C HRSG INSPECTION
FT. MYERS 2	10/12/13	10/18/13	D HRSG INSPECTION
FT. MYERS 2	10/19/13	10/25/13	E HRSG INSPECTION
FT. MYERS 2	10/19/13	10/25/13	F HRSG INSPECTION
FT. MYERS 3	9/2/13	9/22/13	A HGP, OVATION UPGRADE
FT. MYERS 3	7/13/13	8/2/13	B HGP, OVATION UPGRADE
LAUDERDALE 4	4/4/13	4/14/13	A COMBUSTOR INSPECTION
LAUDERDALE 4	10/19/13	11/1/13	BALANCE OF PLANT (PRIMARY STEAM PIPING)
LAUDERDALE 4	4/4/13	4/24/13	B HGP
LAUDERDALE 5	2/23/13	3/15/13	A COMBUSTOR INSPECTION
LAUDERDALE 5	2/23/13	3/5/13	B COMBUSTOR INSPECTION
LAUDERDALE 5	2/23/13	3/8/13	BALANCE OF PLANT (FEEDWATER SYSTEM)
MANATEE 1	1/1/13	7/24/13	ESP, LP1 LP2 TURBINE, MINOR BOILER
MANATEE 2	2/2/13	2/22/13	MAJOR BOILER
MANATEE 3	2/16/13	2/22/13	A HRSG INSPECTION
MANATEE 3	2/23/13	3/1/13	B HRSG INSPECTION

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Line No.	(1)	(2)	(3)	(4)	(5)
1	V. B.	2013	2013		2013
2	Unit	Outage Start	Outage End		Outage Description
3	MARTIN 8	12/14/13	12/20/13		A COMBUSTOR INSPECTION
4	MARTIN 8	12/14/13	12/20/13		B HRSG INSPECTION
5	MARTIN 8	3/2/13	3/8/13		C HRSG INSPECTION
6	MARTIN 8	3/9/13	3/15/13		D HRSG INSPECTION
7	MARTIN 1	6/20/13	12/31/13		ESP, MINOR BOILER, TURBINE VALVES
8	MARTIN 3	10/19/13	10/25/13		A COMBUSTOR INSPECTION, HRSG INSPECTION
9	MARTIN 3	10/25/13	12/7/13		B HGP, REPLACE COMPRESSOR DISCHARGE CASING
10	MARTIN 4	2/23/13	3/1/13		B COMBUSTOR INSPECTION
11	MARTIN 4	3/2/13	4/14/13		A MAJOR, REPLACE COMPRESSOR DISCHARGE CASING, HRSG & GENERATOR INSPECTION
12	PUTNAM	3/16/13	3/25/13		COOLING TOWER FAN
13	PUTNAM 1	10/19/13	12/20/13		1GT2 MAJOR COMBUSTION TURBINE & GENERATOR, HRSG INSPECTION
14	PUTNAM 2	3/16/13	3/29/13		2GT1 HGP, REPLACE CONTROL WIRE, HRSG INSPECTION
15	SANFORD 4	8/6/13	8/12/13		A HRSG INSPECTION
16	SANFORD 4	4/13/13	4/19/13		B HRSG INSPECTION
17	SANFORD 4	1/11/13	1/24/13		C HGP, HRSG & GENERATOR INSPECTION
18	SANFORD 4	3/16/13	3/29/13		D HGP, HRSG & GENERATOR INSPECTION
19	SANFORD 4	3/16/13	5/24/13		HP/IP STEAM TURBINE, STEAM TURBINE GENERATOR, LP EVAPORATOR MODULES
20	SANFORD 5	4/21/13	4/27/13		A HRSG INSPECTION
21	SANFORD 5	9/9/13	9/22/13		B HGP, HRSG INSPECTION
22	SANFORD 5	3/2/13	3/15/13		C HGP, HRSG INSPECTION
23	SANFORD 5	3/2/13	3/8/13		D HRSG INSPECTION
24	ST. JOHNS RIVER POWER PARK 1	3/9/13	4/7/13		MINOR BOILER, FUEL GAS DESULFURIZATION, BOILER FEED PUMP TURBINE
25	TURKEY POINT 5	11/2/13	11/27/13		A HGP & HRSG, S14-S16 BLADES
26	TURKEY POINT 5	8/10/13	9/4/13		B HGP & HRSG, S14-S16 BLADES
27	TURKEY POINT 5	11/2/13	11/27/13		C HGP & HRSG, S14-S16 BLADES
28	TURKEY POINT 5	9/5/13	9/30/13		D HGP & HRSG, S14-S16 BLADES
29	TURKEY POINT 5	11/2/13	11/24/13		STEAM TURBINE VALVES & STEAM TURBINE GENERATOR INSPECTION
30	TURKEY POINT 1	4/28/13	6/11/13		MAJOR BOILER, LP STEAM TURBINE, STEAM TURBINE VALVES & GENERATOR
31	TURKEY POINT 2	3/30/13	4/28/13		SYNCHRONOUS CONDENSER MAINTENANCE
32	WEST COUNTY ENERGY CENTER 1	3/2/13	3/17/13		A COMBUSTOR INSPECTION
33	WEST COUNTY ENERGY CENTER 1	3/19/13	4/3/13		B COMBUSTOR INSPECTION
34	WEST COUNTY ENERGY CENTER 1	4/5/13	4/20/13		C COMBUSTOR INSPECTION
35	WEST COUNTY ENERGY CENTER 2	11/23/13	12/8/13		A COMBUSTOR INSPECTION
36	WEST COUNTY ENERGY CENTER 2	12/8/13	12/23/13		B COMBUSTOR INSPECTION
37	WEST COUNTY ENERGY CENTER 2	11/23/13	12/8/13		C COMBUSTOR INSPECTION
38	WEST COUNTY ENERGY CENTER 3	11/22/13	12/17/13		A HGP, HRSG, GENERATOR INSPECTION
39	WEST COUNTY ENERGY CENTER 3	11/2/13	11/27/13		B HGP, HRSG, GENERATOR INSPECTION
40	WEST COUNTY ENERGY CENTER 3	11/22/13	12/17/13		C HGP, HRSG, GENERATOR INSPECTION
41	WEST COUNTY ENERGY CENTER 3	11/22/13	12/11/13		STEAM TURBINE GENERATOR INSPECTION
42					
43					

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended __/__/__
____ Historical Test Year Ended __/__/__

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl, J.A. Stall, Roxane R. Kennedy

Line No. (1) (2)

VI. INTERCHANGE AND PURCHASED POWER ASSUMPTIONS

A. Contractual Commitments for Scheduled Interchange/Purchased Power

1. Unit Power Purchase (UPS) - Southern Companies

a. Capacity:

(1)	(2)
2012	953
2013	953

b. Capacity and energy costs based on Southern's estimate, subject to true up and audit.

c. Energy costs are recovered through the Fuel Cost Recovery Clause (FCRC) and capacity costs are recovered through the Capacity Cost Recovery Clause (CCRC).

2. Unit Power Purchase - St Johns River Power Park

a. 30% of rated net capacity of each unit is considered purchased power.

b. All energy scheduled by FPL in excess of 20% (FPL owned generation) is considered purchased energy.

c. Capacity costs are recovered through the CCRC. Energy costs are recovered through the FCRC.

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Line No. (1) (2) (3) (4)

3. Power Sold and Economy Energy Purchases (Schedule "OS")

a. Schedule OS sales are based upon projected market prices and expected available generation relative to FPL's projected incremental cost of sales (generation and transmission)

b. Schedule OS purchases are based upon FPL's projected incremental generation cost relative to projected market prices plus incremental costs and transmission costs.

c. Energy & transmission costs of OS purchases are recovered through the FCRC. For OS sales, the FCRC is credited for incremental generation cost, the CCRC is credited for FPL transmission costs incurred to make the sale, Base is credited for the incremental costs of running gas turbines, if applicable, and the FCRC is credited for the gain on a sale.

4. Interchange related to St Lucie Unit 2 Reliability Exchange Agreement

a. Based on P-MArea projection for PSL 1 and PSL 2 output as applied to the contract formula.

5. Schedule of New and Expiring Interchange/Purchase Power Contracts for the period.

a. DeSoto County Generating Company, LLC entered into in 2011 expires December 31, 2012.

b. Oleander Power Project, L.P. entered into in 2002 expires May 31, 2012.

c. Seminole Electric Cooperative, Inc. entered into in 2011 expires on May 31, 2012. - contract executed after 11/14/2011 forecast

d. Tampa Electric Company entered into in 2011 expires on December 31, 2012. - contract executed after 11/14/2011 forecast

6. Purchased Power from Qualifying Facilities:

		Capacity (MW)	Energy (MWH)
a. Firm			
	2012	645	2,722,502
	2013	645	2,722,502
b. As Available			
	2012	n/a	975,980
	2013	n/a	975,980

FLORIDA PUBLIC SERVICE COMMISSION

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl, J.A. Stall, Roxane R. Kennedy

Line No.	(1)	(2)	(3)
1	VI. 7. **Schedule of Sales and Purchased Power Contracts for the Period (contracts impact 2012 and 2013)**		
2		**a. Sales:**	City of Blountstown, Florida full requirements ~10 MW (5/1/2012 to 12/31/2013) - contract executed after 11/14/2011 forecast
3			Florida Keys Electric Cooperative Association, Inc. full requirements ~143 MW (1/1/2012 to 12/31/2013)
4			Utility Board of the City of Key West, Florida 45 MW RTC capacity and energy (1/1/12 to 5/31/13)
5			Lee County Electric Cooperative, Inc. partial requirements up to 300 MW (1/1/12 to 12/31/13)
6			City of Wauchula, Florida full requirements capacity and energy ~15 MW (1/1/12 to 12/31/13)
7		**b. Purchases:**	DeSoto County Generating Company, LLC dated October 24, 2011 (1/1/2012 to 12/31/2012)
8			Oleander Power Project, L.P. dated April 30, 2001 (6/1/2002 to 5/31/2012)
9			Seminole Electric Cooperative, Inc. dated January 5, 2012 (4/1/2012 to 5/31/2012) - contract executed after 11/14/2011 forecast
10			Tampa Electric Company dated December 11, 2011 (1/1/2012 to 12/31/2012) - contract executed after 11/14/2011 forecast
11	VII. FUEL ASSUMPTIONS		
12	A. **Fuel Related Assumptions**		
13	1. **Fossil Fuel**		
14	The current real and nominal fuel price forecast for light and heavy fuel oil, natural gas, coal,		
15	and petroleum coke, and the projection for the availability of natural gas to the FPL system		
16	for 2012 and 2013 was issued on November 14, 2011 and was based on current and projected		
17	market conditions, and existing supply and transportation contracts. This forecast was		
18	used as input into the P-MArea production costing model for development of forecasted information.		
19	2. **Nuclear Fuel**		
20	The Nuclear Fuel Forecast model was used to project fuel costs. The 2013 Fuel Cost Projections used in the impending rate case filing		
21	are consistent with the Approved Operating Schedule dated June 22, 2011.		
22			
23			
24			
25			
26			

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Line No. (1) (2) (3)

VIII. OPERATIONS AND MAINTENANCE AND CAPITAL EXPENDITURES FORECAST ASSUMPTIONS

A. INFLATION RATE FORECAST

See Section II. Inflation Rate Forecast

B. PAY PROGRAMS

1. **Merit Pay Program Increases**
   3%

IX. OTHER ASSUMPTIONS

A. Amount of CWIP and NFIP in Rate Base - FPSC

1. CWIP: All Construction Work in Progress (CWIP) which does not meet the criteria for the accrual of Allowance for Funds Used During Construction (AFUDC) are included in CWIP for rate base in accordance with Rule No. 25-6.0141, Florida Administrative Code.
2. NFIP: All Nuclear Fuel in Process is included in rate base.

B. Amount of CWIP and NFIP in Rate Base - FERC

1. CWIP: None.
2. NFIP: None.

C. AFUDC Rates for Capital Expenditures (FPSC and FERC)

FPL's current AFUDC rate is 6.41% as approved by the Florida Public Service Commission in Order No. PSC-10-0470-PAA-EI, in Docket No. 100133-EI issued on July 23, 2010.

D. AFUDC Debt/Equity Split - FPSC and FERC

	FPSC Ratio	FERC Ratio
1. Debt %	27.31%	31.04%
2. Equity %	72.69%	68.96%

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

FLORIDA PUBLIC SERVICE COMMISSION

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(1) (2) (3) (4)

IX. E. **Depreciation Rates**

1. For the 2013 test year, depreciation expense is based on depreciation rates approved by the Florida Public Service Commission in Docket Nos. 080677-EI / 090130-EI, Order No. PSC-10-0153-FOF-EI issued on March 17, 2010. The Company is required to file its next depreciation study no later than March 2013.
2. For the 2013 test year, dismantlement accruals for the fossil-fueled generating stations are based on the dismantlement accruals approved by the Florida Public Service Commission in Docket Nos. 080677-EI / 090130-EI, Order No. PSC-10-0153-FOF-EI issued on March 17, 2010. The Company is required to file its next dismantlement study no later than March 2013.

F. **Total Line Losses** **2013** **of Net Energy for Load**
5.88%

G. **Company Usage** **2013** **of Net Energy for Load**
0.11%

H. 35% **FEDERAL INCOME TAX RATE (REGULAR)**

I. 5.5% **STATE INCOME TAX RATE**

J. 0.00072 **REGULATORY ASSESSMENT FEE RATE (FPSC)**
Per Rule 25-6.0131,"Investor Owned Electric Company Regulatory Assessment Fee" in the Florida Administrative Code.

Supporting Schedules: E-18 Recap Schedules: E-10, C-40

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

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____ Historical Test Year Ended ___/___/___

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl, J.A. Stall, Roxane R. Kennedy

Line No.		(1)	(2)	
1				
2	K.	2.50%	**GROSS RECEIPTS TAX RATE**	
3			Provided as a pass through to customers as provided in Florida Statute Chapter 203.	
4				
5	L.		**FRANCHISE FEE RATE**	
6		4.73%	**2012**	
7		4.76%	**2013**	
8				
9			Percentage represents composite rate.	
10				
11	M.	**PRIOR YEAR**		
12			Year 2012 Forecast	
13				
14	N.	**TEST YEAR**		
15			Year 2013 Forecast	
16				
17	O.	**HISTORICAL YEAR**		
18			Year 2011	
19				
20	P.	**LAST MONTH OF HISTORICAL DATA**		
21			September 2011	
22				
23	Q.	**MILLAGE RATE FOR PROPERTY TAXES**		
24			The overall millage rate used for historical, prior and test year are as follows:	
25			2011	1.8486000%
26			2012	1.8757000%
27			2013	1.8910000%
28				

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

FLORIDA PUBLIC SERVICE COMMISSION

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl, J.A. Stall, Roxane R. Kennedy

Line No. (1) (2)

R. STATUTORY SALES TAX RATE

6.00% Is the statutory sales tax rate. This may be coupled with a sur-tax that is levied by the County from 1/2% up to 1 1/2%.

6.192% is the blended forecasted rate, based on 2007 actual payments.

S. FEDERAL AND STATE UNEMPLOYMENT TAX RATES

0.6% FUTA on the first $7,000 of wage base per employee

2.25% SUTA on the first $7,000 of wage base per employee

T. FICA TAX RATES

6.2% Social Security Tax on $110,100 wage base for 2011 and on $110,700 wage base for 2012 and $114,900 wage base for 2013.

1.45% Medicare tax on total compensation.

U. Extended Power Uprate (EPU) Assumptions

1. EPU capital projections as of 9/30/2011. These estimates are subject to continuing review and adjustment and actual capital expenditures are subject to change from these estimates.

Supporting Schedules: E-18

Recap Schedules: E-10, C-40

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: Supply a proposed public notice of the company's request for a rate increase suitable for publication.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___
Witness: Marlene M. Santos

Line No.

Proposed Public Notice for Rate Case
INFORMATION ABOUT YOUR ELECTRIC RATES

On March 19, 2012, Florida Power & Light Company (FPL) filed a Petition with the Florida Public Service Commission (FPSC) requesting an increase in its base rates, effective January 1, 2013. The FPSC has assigned Docket No. 120015-EI to FPL's request.

FPL's current base rate agreement will expire at the end of 2012. Key drivers of the need for a base rate increase include, but are not limited to: 1) the impact of accelerated amortization of surplus depreciation; 2) payment for a new, high-efficiency natural gas power plant at Cape Canaveral after it enters into service in mid-2013; 3) increases in the cost of doing business, including those associated with the projected addition of approximately 100,000 new customer accounts; and, 4) resetting the company's return on equity to a more competitive and equitable level.

The requested increase would amount to $6.97 a month, or 23 cents a day, on the base component of a typical, 1,000 kWh residential customer bill. Because of reductions in fuel use as a result of investments in high-efficiency power plants, reductions in the cost of natural gas, and other adjustments to the bill, the actual bill impact on a typical, 1,000 kWh residential customer bill is projected at $2.48 per month, or 8 cents per day. Even with the adjustment, FPL expects that its customer bill would remain the lowest out of 55 electric utilities in the state and below the national average. In addition, the company expects that the bill will still be about 10 percent lower than it was in 2006.

The FPSC will hold customer service hearings throughout FPL's service territory to receive input from customers about the quality of FPL's service and the proposed base rate adjustment. The dates and locations of the service hearings will be published in a separate notice after they have been scheduled.

A copy of FPL's petition for an increase in base rates and supporting documentation is available for inspection during regular business hours at FPL's office at 700 Universe Boulevard, Juno Beach, Florida and 9250 West Flagler Street, Miami, Florida. Information about the base rate request is also available at FPL's website, www.FPL.com/answers and at the FPSC's website, www.psc.state.fl.us.

Supporting Schedules: Recap Schedules: