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August 8, 2002

-VIA FEDERAL EXPRESS-

Blanca S. Bayó
Director, Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 020007-EI

Dear Ms. Bayó:

I am enclosing for filing in the above docket the original and seven (7) copies of Florida Power & Light Company's Petition for Approval of the Environmental Cost Recovery Estimated/Actual True-Up Amount for the Period January 2002 Through December 2002 and the Testimony and Exhibits of Korel M. Dubin and Randall R. LaBauve. Also enclosed is a diskette containing the electronic version of the petition. The enclosed diskette is HD density, the operating system is Windows 2000, and the word processing software in which the document appears is Word 2000.

If there are any questions regarding this transmittal, please contact me at 305-577-2939.

Sincerely,

Korel M. Dubin for JTB

John T. Butler, P.A.

Enclosure
cc: Counsel for Parties of Record (w/encl.)

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CERTIFICATE OF SERVICE
Docket No. 020007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by United States Mail this 8th day of August, 2002, to the following:

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By: Karel M. Dub for JTB
John T. Butler, P.A.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	))	**Docket No. 020007-EI Filed August 9, 2002**

PETITION FOR APPROVAL OF THE ENVIRONMENTAL COST RECOVERY ESTIMATED/ACTUAL TRUE-UP AMOUNT FOR PERIOD JANUARY 2002 THROUGH DECEMBER 2002

Florida Power & Light Company ("FPL") pursuant to Order No. PSC-93-1580-FOF-EI, hereby petitions this Commission to approve the calculation of the Environmental Cost Recovery ("ECR") Estimated/Actual True-up underrecovery amount of $7,799,426 for the period January 2002 through December 2002.

In support of this Petition, FPL incorporates the prepared written testimony of and documents sponsored by Ms. K. M. Dubin and Mr. R. R. LaBauve and states:

1. Florida Statutes Section 366.8255, which became effective on April 13, 1993, authorizes the Commission to review and approve the recovery of prudently incurred Environmental Compliance Costs.

2. Order PSC-99-2513-FOF-EI issued on December 22, 1999, requires utilities to file their current period estimated/actual true-ups at least 90 days prior to the ECR clause hearing.

3. FPL submits for recovery the Estimated/Actual True-up underrecovery of $7,799,426 for the January 2002 through December 2002 period, as set forth in the testimony and exhibits of Ms. K. M. Dubin and Mr. R. R. LaBauve. Pursuant to Order PSC-01-2463-FOF-EI, FPL has included actual costs for the period April 15, 2002 through June 30, 2002 and revised estimates for the period July through December 2002. Per Order No. PSC-99-0519-AS-EI, costs for the period January 1, 2002 through

April 14, 2002 were recorded in a non-recoverable account and are not being included for recovery through the ECR.

4. Mr. R. R. LaBauve's prepared testimony and exhibit presents a new environmental compliance activity for recovery through the ECR: the Pipeline Integrity Management Program (the "PIM Program"). His testimony includes a description of the PIM Program, a copy of the regulation with which this program is intended to comply, the costs associated with the program, and a demonstration of the appropriateness of the program. This information shows that the PIM Program for which FPL requests authorization to recover are prudent and meet the requirements for recovery set forth in Section 366.8255, Fla. Statutes.

5. The calculation of the ECR Estimated/Actual True-up amount for the period January 2002 through December 2002 is contained in Commission schedules 42-IE through 42-8E which are attached as Appendix I to the prepared written testimony of FPL witness K. M. Dubin filed in Docket No. 020007-EI, and are incorporated herein by reference.

WHEREFORE, FPL respectfully requests the Commission to approve the Environmental Cost Recovery Estimated/Actual True-up amount requested herein for the January 2002 through December 2002 period.

DATED this 9th day of August, 2002.

Respectfully submitted,

STEEL HECTOR & DAVIS LLP
215 South Monroe Street
Suite 601
Tallahassee, Florida 32301-1804
Attorneys for Florida Power & Light

By: Korel M. Dubin for JTB
John T. Butler, P. A.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020007-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 9, 2002

ENVIRONMENTAL COST RECOVERY

ESTIMATED/ACTUAL TRUE-UP
JANUARY 2002 THROUGH DECEMBER 2002

TESTIMONY & EXHIBITS OF:

K. M. DUBIN
R. R. LABAUVE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 020007-EI

August 9, 2002

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review and approval the Environmental Estimated/Actual True-up Costs associated with FPL Environmental Compliance activities for the period April 15, 2002 through December 31, 2002.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. The exhibit consists of eight documents, PSC Forms 42-1E through 42-8E, included in Appendix I. Form 42-1E provides a summary of the Estimated/Actual True-up amount for the period April 15, 2002 through December 31, 2002. Forms 42-2E and 42-3E reflect the calculation of the Estimated/Actual True-up amount for the period. Forms 42-4E and 42-6E reflect the Estimated/Actual O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the Estimated/Actual period. Form 42-8E (pages 1 through 23) reflects return on capital investments, depreciation, and taxes by project.

Q. What is the basis for the Estimated/Actual True-up amount that FPL is requesting for April 15, 2002 through December 31, 2002?

A. In Order No. PSC-01-2463-FOF-EI, the Commission approved the following stipulation concerning implementation of the provision in FPL's 1999 Stipulation and Settlement Agreement concerning recovery of Environmental Compliance Costs:

> FPL should be required to follow the provisions of the stipulation in Order No. PSC-99-0519-AS-EI, which state: "For 2002, FPL will not be allowed to recover any costs through the environmental cost recovery docket. FPL may, however, petition to recover in 2003 prudent environmental

costs incurred after the expiration of the three-year term of this Stipulation and Settlement in 2002." FPL is authorized to recover these prudently incurred environmental costs in 2003. Interest, however, will not accrue on these expenses.

Q. What is the Estimated/Actual True-up amount that FPL is requesting for April 15, 2002 through December 31, 2002?

A. The Estimated/Actual True-up amount for the period April 15, 2002 through December 31, 2002 is an underrecovery of $7,799,426. Per Order No. PSC-01-2463-FOF-EI, this estimated/actual true-up underrecovery of $7,799,426 does not include interest. This underrecovery is shown on Form 42-1E, Line 4.

Q. Please explain the calculation of the ECRC Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount. The calculation for the Estimated/Actual True-up amount for the period April 15, 2002 through December 31, 2002 is an underrecovery or $7,799,426 (Appendix I, Page 4, line 5 plus line 6).

Q. Are all costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects previously approved by the Commission?

A. Yes, with the exception of the St. Lucie Turtle Net Project filed on June 18, 2002, and the Pipeline Integrity Management Program Project presented in the testimony of R. LaBauve.

On June 18, 2002, FPL filed a Petition for Approval of Environmental Cost Recovery of the St. Lucie Turtle Net Project for the period April 15, 2002 through December 31, 2002. On July 3, 2002, The Commission assigned Docket No. 020648-EI to the Petition. The Staff Recommendation on this Docket is due August 22, 2002, and this issue will be addressed at the Agenda Conference on September 3, 2002. Consistent with the Petition, FPL has included projected O&M costs of $15,000 and Capital costs of $17,975 for the period April 15, 2002 through December 2002 for this project.

Additionally, FPL is requesting approval through the Environmental Cost Recovery Clause of the Pipeline Integrity Management Program Project. This new project is addressed in the direct testimony of FPL witness Randall LaBauve, which is being prefiled contemporaneously with this testimony. Based on the cost estimate contained in Mr. LaBauve's testimony, FPL has included projected O&M costs of $100,000 for the period April 15, 2002 through December 2002 for this project.

Q. How do the Estimated/Actual project expenditures for January 15, 2002 through December 31, 2002 period compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $351,477 or 9.1% lower than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $89,164 or 2.0% lower than projected. Below are variance explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided as Form 42-8E, pages 1 through 23 (Appendix I, Pages 13 through 35).

1. Air Operating Permit Fees (Project No. 1) - O & M

Project expenditures are estimated to be $15,852 or 0.8% higher than previously projected. This variance is primarily due to fluctuations in permit fees for 2002, which are based on tons of pollutants discharged from the fossil fuel fired power plants during the previous year. These emissions are proportionate to the amount of time and the type of fuel used at each plant. These variables fluctuate daily, based on weather conditions and fuel type.

2. Continuous Emission Monitoring Systems (Project No. 3a) - O & M

Project expenditures are estimated to be $46,593 or 11.4% lower than previously projected. This variance is primarily due to a delay in the payment of the CEMS software support service contract. The original software vendor, KVB-Entertec, has been acquired by GE Energy Service and therefore the scheduled payment was not made to KVB-Entertec. FPL is in the final stages of negotiations with GE Energy Services to determine the terms and conditions of the software support contract.

3. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5a) - O&M

Project expenditures are estimated to be $20,640 or 42.8% higher than previously projected. The majority of the storage tank work was performed at the beginning of the year versus the latter part of the year, as originally projected.

4. RCRA Corrective Action (Project No. 13) - O&M

Project expenditures are estimated to be $25,000 or 71.4% lower than previously projected. This variance is primarily due to a decrease in projected costs associated with the preparation of a facility for an expected assessment by the EPA, which did not occur. These expenditures are contingent upon receiving notification from EPA of its intent to move forward with the process.

5. NPDES Permit Fees (Project No. 14) - O&M

Project expenditures are estimated to be $13,500 or 45.0% higher than previously projected. This variance is primarily due to incurring costs for a permit renewal for Cape Canaveral Plant in 2002 rather than 2003 as originally projected. Additionally, payments were made for sodium exemptions at Cape Canaveral Plant, Fort Myers Plant, and Port Everglades Plant that were not included in the original projections.

6. Disposal of Noncontainerized Liquid Waste (Project No. 17a) - O&M

Project expenditures are estimated to be $33,268 or 12.7% lower than previously projected. This variance is primarily due to the deferral of the ash-processing project for Riviera Plant to 2003 due to conflicts in scheduling the ash press. This equipment separates ash from the water and is integral to the job. The ash press will not be available for use at the Riviera Plant until late December 2002.

7. Substation Pollutant Discharge Prevention & Removal - Distribution (Project No. 19a) - O&M

Project expenditures are estimated to be $321,104 or 26.4% lower than previously projected. This variance is primarily due to extremely heavy rains from the end of May to mid July, which prevented the completion of work related to the Distribution portion of the project. Deferrals of work in the Transmission portion of the project for operational reasons (see variance explanation for Project 19b below) prevented the shifting of unused funding and resources to that portion of the project.

8. Substation Pollutant Discharge Prevention & Removal - Transmission (Project No. 19b) - O&M

Project expenditures are estimated to be $88,240 or 13.5% lower than previously projected. Work on this project was deferred for operational reasons.

To perform the planned project work, the equipment must be de-energized (clearances obtained) and taken out of service, thereby shutting down part of the electrical grid. Outside events can impact the ability to remove (de-energize) this equipment from the system.

9. Continuous Emission Monitoring Systems (Project No. 3b) - Capital

The variance of $50,494 or 4.0% lower than projected is due to the retirements resulting from the Ft. Myers and Sanford repowering projects that were not included in the original projections. By reducing net plant, these retirements caused both the annual depreciation and return on investment to be lower than projected.

10. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5b) - Capital

The variance of $22,867 or 1.7% lower than projected is due to the retirements resulting from the Ft. Myers and Sanford repowering projects that were not included in the original projections. By reducing net plant, these retirements caused both the annual depreciation and return on investment to be lower than projected.

11. SO2 Allowances - Negative Return on Investment - Capital

The variance of $35,621, or 46.4% higher than projected is due to higher than anticipated gains from the DOE sales of emission allowances in 2002.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 020007-EI

August 9, 2002

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Environmental Services.

Q. Have you previously testified in predecessors to this docket?

A. Yes, I have.

Q. Please describe your educational and professional background and experience.

A. I received a Bachelor of Arts degree in Psychology from Louisiana State University in 1983 and a Juris Doctor degree from Louisiana State University in 1986. I joined FPL in 1995 as an Environmental Lawyer and in 1996 assumed the responsibility of Director of Environmental Services.

In July of 2002, I assumed the responsibility of Vice President of Environmental Services. Prior to joining FPL I was the Director of Environmental Affairs for Entergy Services, Incorporated located in Little Rock, Arkansas and prior to that practiced law with Milling, Benson, Woodward, Hilliard, Pierson and Miller in New Orleans, Louisiana.

I am responsible for directing the overall corporate environmental planning, programs, licensing, and permitting activities to ensure the basic objective of obtaining and maintaining the federal, state, regional and local government approvals necessary to site, construct and operate FPL's power plants, transmission lines, and fuel facilities and maintain compliance with environmental laws.

Q. Have you prepared, or caused to be prepared under your direction, supervision or control, an exhibit in this proceeding?

A. Yes, I have. The exhibit consists of Document RRL-1 - - U. S. Department of Transportation Regulation 49 CFR Part 195.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present for Commission review and approval FPL's proposal to recover through the ECRC the costs associated with a new environmental activity, the Pipeline Integrity Management Program Project, as required by U.S. Department of Transportation Regulation 49 CFR Part 195. This regulation requires operators with 500 or fewer miles of regulated pipelines to establish a program for managing the integrity of pipelines that could affect high consequence areas if a leak or rupture occurs. The objective of this requirement is to improve the integrity of pipeline systems in the U.S. in order to protect public safety, human health, and the environment.

Q. Please describe the law or regulation requiring this activity.

A. On January 16, 2002, 49 CFR Part 195 was amended to include a Final Rule on Implementing Integrity Management. This Final Rule took effect on February 15, 2002. Per this regulation, all hazardous liquid pipelines and carbon dioxide pipelines with 500 or fewer miles of regulated pipelines that could affect high consequence areas must develop and implement a pipeline integrity management program. High consequence areas include populated areas defined by the U.S. Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways.

Additionally, the regulation requires continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventative, and mitigative actions.

Q. How does this new law or regulation affect FPL?

A. FPL currently owns four hazardous liquid pipelines: the Martin 18 inch pipeline, the Martin 30 inch pipeline, the Manatee 16 inch pipeline, and the Dania Spur 8 inch Pipeline, that are subject to this new rule and must comply with the new requirements.

Q. Please describe the Pipeline Integrity Management Program Project.

A. FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Q. What is a baseline assessment plan?

A. A baseline assessment plan must include the inline inspection tool or hydrostatic pressure test method which is selected to assess the integrity of the pipeline, a schedule for completing the integrity assessment, an explanation of the assessment methods selected, and an explanation of risk factors considered in establishing the assessment schedule.

Q. What is an information analysis?

A. Periodic risk analyses must be performed on the integrity of each pipeline segment where all available information about the integrity of the entire pipeline and the consequences of a failure must be included. This includes information critical to determining the potential for, and the prevention of damage to the pipeline segment caused by third party damage (i.e. excavation), threats to the pipeline from corrosion, defects, operator error, natural causes, consequences of a failure to the environment and the public, information on how a failure would affect an high consequence area, and pertinent data gathered from other inspections, tests, surveillance, and patrols.

Q. What preventative and mitigating measures must be taken to protect the high consequence area?

A. Measures must be taken to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. A risk analysis of the pipeline segment must be conducted to identify additional actions to enhance public safety and environmental protection. These actions include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing Emergency Flow Restricting Devices on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

In identifying the need for additional preventative and mitigating measures, a means of leak detection is also required. An evaluation must be performed to address the likelihood of a pipeline release occurring and how a release could affect the high consequence area.

Q. What processes are required to maintain a pipeline's integrity?

A. Development and implementation of the plan including all of the required components are required to maintain a pipeline's integrity. After completing the baseline integrity assessment, the pipeline must be continually assessed at specified intervals and periodically evaluated for the integrity of each pipeline segment that could affect a high consequence area. Pipeline integrity must be assessed at intervals not to exceed five years, depending on the risk the pipeline poses to the high consequence area.

Q. What are the compliance dates for this project?

A. Each pipeline or pipeline segment that could affect a high consequence area must be identified by November 18, 2002.

A written integrity management program that addresses the risks on each segment of pipeline must be developed by February 18, 2003.

Fifty percent of the pipeline must be assessed on an expedited basis, beginning with the highest risk pipe. This expedited assessment must be completed to later than August 16, 2005.

Complete baseline assessments must be performed no later than February 17, 2009.

Q. Has FPL estimated the cost of the proposed Project?

A. Yes. FPL estimates total project costs for its four hazardous liquid pipelines at Martin (18" and 30"), Manatee and Dania Spur for 2002 through 2004 to be approximately $1,560,000. Costs for 2005 through 2009 will be based on the assessments and data gathered in 2002 through 2004. On-going program development and implementation is estimated to cost approximately $150,000 of O&M per year, and baseline and on-going (every five years) assessments will cost approximately $100,000 of O&M per assessment. Total estimated O&M costs for 2003 through 2004 are $400,000. Preventative measures to increase pipeline integrity in the form of leak detection will require capital expenditures. The initial capital projects that have been identified are metering for the Martin 30" pipeline and metering and SCADA (system control and data acquisition) for the Dania Spur pipeline. The associated costs are approximately $1,060,000 for 2003 through 2004.

Q. Has FPL estimated how much will be spent on the Pipeline Integrity Management Program Project in 2002?

A. Yes. FPL's O&M cost estimate is $100,000 for 2002. This estimate is for the development of the written Pipeline Integrity Management Plan and the identification of the high consequence areas.

Q. Were there any costs for this project in the MFR's that FPL filed in Docket No. 001148-EI?

A. No.

Q. How will FPL ensure that the costs incurred are prudent and reasonable?

A. A Request for Proposal (RFP) with detailed specifications will be issued for program development and will be awarded to the lowest bidder. In-house resources and current contracted resources will be utilized where practical and cost effective. Capital improvement bids will also be awarded through RFPs based on cost effectiveness.

Q. What alternatives did FPL consider?

A. There are no alternatives to developing the above program, due to the prescriptive nature of the regulation. Hydrocarbon monitoring was considered as an alternative to metering but is significantly more expensive, and installation requires pipeline excavation which disrupts operations.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

APRIL 15, 2002 - DECEMBER 31, 2002
ESTIMATED / ACTUAL TRUE-UP

KMD-2
DOCKET NO. 020007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT ______
PAGES 1-35

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated / Actual True-up for the
Period - April 15, 2002 through December 31, 2002

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	($7,799,426)
2	Interest Provision (Form 42-3E, Page 2 of 2, Line 10)	$0
3	Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10)	$0
4	Estimated/Actual True-up to be refunded/(recovered) in January 2003 through December 2003 Period	($7,799,426)

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
April 15, 2002 through December 31, 2002

Line No.		January	February	March	April *	May	June
1	ECRC Revenues (net of Revenue Taxes)	$0	$0	$0	$0	$0	$0
2	True-up Provision (Order No. PSC-01-2463-FOF-EI)	0	0	0	0	0	0
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	0	0	0	0	0	0
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	0	0	0	55,363	101,438	119,124
	b - Capital Investment Projects (Form 42-7A, Line 9)	0	0	0	273,463	509,761	506,673
	c - Total Jurisdictional ECRC Costs	0	0	0	328,826	611,199	625,797
5	Over/(Under) Recovery (Line 3 - Line 4c)	0	0	0	(328,826)	(611,199)	(625,797)
6	Interest Provision (Form 42-3A, Line 10)	0	0	0	0	0	0
7	Beginning Balance True-Up & Interest Provision	0	0	0	0	(328,826)	(940,025)
	a - Deferred True-Up from Jan to Dec 2001 (Form 42-1A, Line 9)	0	0	0	0	0	0
8	True-Up Collected /(Refunded) (See Line 2)	0	0	0	0	0	0
9	End of Period True-Up (Lines 5+6+7+7a+8)	0	0	0	(328,826)	(940,025)	(1,565,822)
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$0	$0	$0	($328,826)	($940,025)	($1,565,822)
		0	0	0	(328,826)	(611,199)	(625,797)

* NOTE: In accordance with Order No. PSC-01-2463-FOF-EI only 16/30 of April's costs are recoverable the ECRC.

3

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
April 15, 2002 through December 31, 2002

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$0	$0	$0	$0	$0	$0	$0
2	True-up Provision (Order No. PSC-01-2463-FOF-EI)	0	0	0	0	0	0	0
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	0	0	0	0	0	0	0
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	128,040	64,524	93,657	309,288	251,092	2,356,007	3,478,533
	b - Capital Investment Projects (Form 42-7A, Line 9)	504,904	503,394	501,882	503,887	506,497	510,432	4,320,893
	c - Total Jurisdictional ECRC Costs	632,944	567,918	595,539	813,175	757,589	2,866,439	7,799,426
5	Over/(Under) Recovery (Line 3 - Line 4c)	(632,944)	(567,918)	(595,539)	(813,175)	(757,589)	(2,866,439)	(7,799,426)
6	Interest Provision (Form 42-3A, Line 10)	0	0	0	0	0	0	0
7	Beginning Balance True-Up & Interest Provision	(1,565,822)	(2,198,766)	(2,766,684)	(3,362,223)	(4,175,398)	(4,932,987)	0
	a - *Deferred True-Up from Jan to Dec 2001 (Form 42-1A, Line 9)*	0	0	0	0	0	0	0
8	True-Up Collected /(Refunded) (See Line 2)	0	0	0	0	0	0	0
9	End of Period True-Up (Lines 5+6+7+7a+8)	(2,198,766)	(2,766,684)	(3,362,223)	(4,175,398)	(4,932,987)	(7,799,426)	(7,799,425)
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	($2,198,766)	($2,766,684)	($3,362,223)	($4,175,398)	($4,932,987)	($7,799,426)	($7,799,425)
		(632,944)	(567,918)	(595,539)	(813,175)	(757,589)	(2,866,439)	

* NOTE: In accordance with Order No. PSC-01-2463-FOF-EI only 16/30 of April's costs are recoverable the ECRC.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
April 15, 2002 through December 31, 2002

Interest Provision (in Dollars) **

Line No.		January	February	March	April *	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$0	$0	$0	$0	($328,826)	($940,025)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	0	0	0	(328,826)	(940,025)	(1,565,822)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$0	$0	$0	($328,826)	($1,268,851)	($2,505,847)
4	Average True-Up Amount (Line 3 x 1/2)	$0	$0	$0	($164,413)	($634,426)	($1,252,924)
5	Interest Rate (First Day of Reporting Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0 00000%
6	Interest Rate (First Day of Subsequent Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
8	Average Interest Rate (Line 7 x 1/2)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
10	Interest Provision for the Month (Line 4 x Line 9)	$0	$0	$0	$0	$0	$0

** NOTE: In accordance with Order No. PSC-01-2463-FOF-EI no interest is to be calculated on the underrecovery during 2002.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
April 15, 2002 through December 31, 2002

Interest Provision (in Dollars) **

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	($1,565,822)	($2,198,766)	($2,766,684)	($3,362,223)	($4,175,398)	($4,932,987)	($20,270,731)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(2,198,766)	(2,766,684)	(3,362,223)	(4,175,398)	(4,932,987)	(7,799,426)	(28,070,157)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	($3,764,588)	($4,965,450)	($6,128,907)	($7,537,621)	($9,108,385)	($12,732,413)	($48,340,888)
4	Average True-Up Amount (Line 3 x 1/2)	($1,882,294)	($2,482,725)	($3,064,454)	($3,768,811)	($4,554,193)	($6,366,207)	($24,170,444)
5	Interest Rate (First Day of Reporting Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$0	$0	$0	$0	$0	$0	$0

** NOTE: In accordance with Order No. PSC-01-2463-FOF-EI no interest is to be calculated on the underrecovery during 2002.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

Variance Report of O&M Activities
(in Dollars)

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
	1 Air Operating Permit Fees-O&M	$2,032,852	$2,017,000	$15,852	0.8%
	3a Continuous Emission Monitoring Systems-O&M	$362,528	$409,121	($46,593)	-11.4%
	4a Clean Closure Equivalency-O&M	$0	$0	$0	0.0%
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$68,809	$48,169	$20,640	42.8%
	8a Oil Spill Cleanup/Response Equipment-O&M	$59,632	$66,112	($6,480)	-9.8%
	13 RCRA Corrective Action-O&M	$10,000	$35,000	($25,000)	-71.4%
	14 NPDES Permit Fees-O&M	$43,500	$30,000	$13,500	45.0%
	17a Disposal of Noncontainerized Liquid Waste-O&M	$228,232	$261,500	($33,268)	-12.7%
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$893,146	$1,214,250	($321,104)	-26.4%
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$566,260	$654,500	($88,240)	-13.5%
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($420,174)	($420,174)	$0	0.0%
	20 Wastewater Discharge Elimination & Reuse	$0	$0	$0	0.0%
	NA Amortization of Gains on Sales of Emissions Allowances	($452,345)	($456,561)	$4,216	-0.9%
	21 St. Lucie Turtle Net	$15,000	$0	$15,000	100.0%
	22 Pipeline Integrity Management	$100,000	$0	$100,000	100.0%
2	Total O&M Activities	$3,507,440	$3,858,917	($351,477)	-9.1%
3	Recoverable Costs Allocated to Energy	$2,258,297	$2,331,358	($73,061)	-3.1%
4a	Recoverable Costs Allocated to CP Demand	$566,084	$523,396	$42,688	8.2%
4b	Recoverable Costs Allocated to GCP Demand	$683,059	$1,004,163	($321,104)	-32.0%

Notes:
Column(1) is the 12-Month Totals on Form 42-5E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-01-2463-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

O&M Activities
(in Dollars)

Line		Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	End 6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees-O&M	$0	$0	$0	$ 3,562	$ 6,145	$ 6,145	$ 15,852
	3a Continuous Emission Monitoring Systems-O&M	0	0	0	7,490	20,980	16,204	44,674
	4a Clean Closure Equivalency-O&M	0	0	0	0	0	0	0
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	0	0	2,253	3,786	28,766	34,805
	8a Oil Spill Cleanup/Response Equipment-O&M	0	0	0	3,115	3,250	6,598	12,963
	13 RCRA Corrective Action-O&M	0	0	0	0	0	0	0
	14 NPDES Permit Fees-O&M	0	0	0	0	13,500	0	13,500
	17a Disposal of Noncontainerized Liquid Waste-O&M	0	0	0	11,714	2,927	1,591	16,232
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	0	0	0	51,306	154,037	108,303	313,646
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	0	0	33,030	83,018	41,716	157,764
	19c Substation Pollutant Discharge Prevention & Removal - Costs included in Base Rates	0	0	0	(46,686)	(46,686)	(46,686)	(140,058)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0
	NA Amortization of Gains on Sales of Emissions Allowances	0	0	0	(10,142)	(139,880)	(43,189)	(193,211)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	0	0	0	0	0	0	0
2	Total of O&M Activities	$0	$0	$0	$ 55,642	$ 101,077	$ 119,448	$ 276,167
3	Recoverable Costs Allocated to Energy	$0	$0	$0	$16,484	($101,988)	($11,238)	$ (96,741)
4a	Recoverable Costs Allocated to CP Demand	$0	$0	$0	$11,195	$72,371	$45,726	$ 129,291
4b	Recoverable Costs Allocated to GCP Demand	$0	$0	$0	$ 27,963	$ 130,694	$ 84,960	$243,617
5	Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	
6a	Retail CP Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$0	$0	$0	$16,313	($100,929)	($11,121)	($95,737)
8a	Jurisdictional CP Demand Recoverable Costs (B)	$0	$0	$0	$11,087	$71,673	$45,285	$128,045
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$0	$0	$0	$27,963	$130,694	$84,960	$243,617
9	Total Jurisdictional Recoverable Costs for O&M Activities	$0	$0	$0	$ 55,363	$ 101,438	$ 119,124	$ 275,925

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not tie due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

O&M Activities
(in Dollars)

Line		Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1	Description of O&M Activities											
1	Air Operating Permit Fees-O&M	$ -	$ -	$ -	$ -	$ -	$ 2,017,000	$ 2,017,000	$ 2,032,852	-		$ 2,032,852
3a	Continuous Emission Monitoring Systems-O&M	63,838	29,674	37,106	71,268	37,106	78,862	317,854	362,528	-		362,528
4a	Clean Closure Equivalency-O&M	0	0	0	0	0	0	0	0	-		-
5a	Maintenance of Stationary Above Ground Fue Storage Tanks-O&M	5,666	5,666	5,666	5,666	5,666	5,674	34,004	68,809	68,809		-
8a	Oil Spill Cleanup/Response Equipment-O&M	7,777	7,777	7,777	7,777	7,777	7,784	46,669	59,632	-		59,632
13	RCRA Corrective Action-O&M	10,000	0	0	0	0	0	10,000	10,000	10,000		-
14	NPDES Permit Fees-O&M	15,000	0	0	0	15,000	0	30,000	43,500	43,500		-
17a	Disposal of Noncontainerized Liquid Waste-O&M	23,000	18,000	30,000	38,000	35,000	68,000	212,000	228,232			228,232
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	14,920	14,920	14,920	230,420	166,420	137,900	579,500	893,146		893,146	
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	79,084	79,084	79,084	47,084	75,080	49,080	408,496	566,260	522,702		43,558
19c	Substation Pollutant Discharge Prevention & Removal - Costs included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(420,174)	(193,926)	(210,087)	(16,161)
20	Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
NA	Amortization of Gains on Sales of Emissions Allowances	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(259,134)	(452,345)			(452,345)
21	St. Lucie Turtle Net	0	0	10,000	0	0	5,000	15,000	15,000	15,000		
22	Pipeline Integrity Management	0	0	0	0	0	100,000	100,000	100,000	100,000		
2	Total of O&M Activities	$ 129,410	$ 65,246	$ 94,678	$ 310,340	$ 252,174	$ 2,379,425	$ 3,231,273	$ 3,507,440	$ 566,084	$ 683,059	$ 2,258,297
3	Recoverable Costs Allocated to Energy	$ 55,714	$ 16,550	$ 35,982	$ 75,682	$ 40,674	$ 2,130,437	$ 2,355,038	$ 2,258,297			
4a	Recoverable Costs Allocated to CP Demand	$ 82,119	$ 57,119	$ 67,119	$ 27,581	$ 68,423	$ 134,431	$ 436,793	$ 566,084			
4b	Recoverable Costs Allocated to GCP Demand	$ (8,423)	$ (8,423)	$ (8,423)	$ 207,077	$ 143,077	$ 114,557	$ 439,442	$ 683,059			
5	Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%					
6a	Retail CP Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 55,135	$ 16,378	$ 35,608	$ 74,896	$ 40,251	$ 2,108,315	$ 2,330,583	$ 2,234,846			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 81,328	$ 56,569	$ 66,472	$ 27,315	$ 67,764	$ 133,135	$ 432,583	$ 560,628			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	($8,423)	($8,423)	$ (8,423)	$ 207,077	$ 143,077	$ 114,557	$ 439,442	$ 683,059			
9	Total Jurisdictional Recoverable Costs for O&M Activities	$ 128,040	$ 64,524	$ 93,657	$ 309,288	$ 251,092	$ 2,356,007	$ 3,202,608	$ 3,478,533			

Notes.
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not tie due to rounding.

Form 42-6E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology-Capital	$ 1,559,050	$ 1,552,832	$ 6,218	0.4%
3b	Continuous Emission Monitoring Systems-Capital	1,213,310	1,263,804	(50,494)	-4.0%
4b	Clean Closure Equivalency-Capital	4,561	4,544	17	0.4%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,317,287	1,340,154	(22,867)	-1.7%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	2,533	2,523	10	0.4%
8b	Oil Spill Cleanup/Response Equipment-Capital	96,561	102,018	(5,457)	-5.3%
10	Relocate Storm Water Runoff-Capital	8,751	8,716	35	0.4%
NA	SO2 Allowances-Negative Return on Investment	(112,427)	(76,806)	(35,621)	46.4%
12	Scherer Discharge Pipeline-Capital	67,190	66,925	265	0.4%
17b	Disposal of Noncontainerized Liquid Wate-Capital	38,511	38,356	155	0.4%
20	Wastewater Discharge Elimination & Reuse	151,746	151,146	600	0.4%
21	St. Lucie Turtle Net	17,975	0	17,975	100.0%
2	Total Investment Projects-Recoverable Costs	$ 4,365,048	$ 4,454,212	$ (89,164)	-2.0%
3	Recoverable Costs Allocated to Energy	$ 2,791,096	$ 2,871,706	$ (80,610)	-2.8%
4	Recoverable Costs Allocated to Demand	$ 1,573,952	$ 1,582,506	$ (8,554)	-0.5%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-01-2463-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1 Description of Investment Projects (A)							
2 Low NOx Burner Technology-Capital	$0	$0	$0	$99,471	$185,606	$184,703	$469,780
3b Continuous Emission Monitoring Systems-Capital	0	0	0	77,110	143,967	143,392	364,469
4b Clean Closure Equivalency-Capital	0	0	0	290	540	539	1,369
5b Maintenance of Stationary Above Ground Fuel	0	0	0	82,596	154,634	154,394	391,624
Storage Tanks-Capital	0	0	0				
7 Relocate Turbine Lube Oil Underground Piping	0	0	0	161	301	300	762
to Above Ground-Capital	0	0	0				
8b Oil Spill Cleanup/Response Equipment-Capital	0	0	0	6,059	11,296	11,232	28,587
10 Relocate Storm Water Runoff-Capital	0	0	0	553	1,034	1,031	2,618
NA SO2 Allowances-Negative Return on Investment	0	0	0	(6,317)	(12,928)	(14,152)	(33,397)
12 Scherer Discharge Pipeline-Capital	0	0	0	4,254	7,952	7,928	20,134
17 Disposal of NonContainerized Liquid Waste-Capital	0	0	0	2,476	4,612	4,582	11,670
20 Wastewater Discharge Elimination and Reuse	0	0	0	9,606	17,958	17,903	45,467
21 St. Lucie Turtle Net Project	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$0	$0	$0	$ 276,259	$ 514,972	$ 511,852	$ 1,303,083
3 Recoverable Costs Allocated to Energy	$0	$0	$0	$ 178,417	$ 331,901	$ 329,167	$ 839,485
4 Recoverable Costs Allocated to Demand	$0	$0	$0	$ 97,842	$ 183,071	$ 182,685	$ 463,598
5 Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	
6 Retail Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	
7 Jurisdictional Energy Recoverable Costs (B)	$0	$0	$0	$ 176,565	$ 328,455	$ 325,749	$ 830,768
8 Jurisdictional Demand Recoverable Costs (C)	$0	$0	$0	$ 96,898	$ 181,306	$ 180,924	$ 459,129
9 Total Jurisdictional Recoverable Costs for Investment Projects	$0	$0	$0	$ 273,463	$ 509,761	$ 506,673	$ 1,289,897

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
April 15, 2002 - December 31, 2002

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1 Description of Investment Projects (A)										
2 Low NOx Burner Technology-Capital	$183,801	$182,898	$181,996	$181,094	$180,192	$179,289	$1,089,270	$1,559,050	-	$1,559,050
3b Continuous Emission Monitoring Systems-Capital	142,817	142,280	141,742	141,205	140,667	140,130	$848,841	$1,213,310	-	1,213,310
4b Clean Closure Equivalency-Capital	537	535	533	531	529	527	$3,192	$4,561	4,210	351
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	154,153	153,848	153,543	153,239	152,934	157,946	$925,663	$1,317,287	1,215,957	101,330
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	298	297	296	295	293	292	$1,771	$2,533	2,338	195
8b Oil Spill Cleanup/Response Equipment-Capital	11,168	11,154	11,140	11,075	11,628	11,809	$67,974	$96,561	89,133	7,428
10 Relocate Storm Water Runoff-Capital	1,029	1,026	1,023	1,021	1,018	1,016	$6,133	$8,751	8,078	673
NA SO2 Allowances-Negative Return on Investment	(14,041)	(13,693)	(13,345)	(12,998)	(12,650)	(12,303)	($79,030)	($112,427)	-	(112,427)
12 Scherer Discharge Pipeline-Capital	7,904	7,879	7,855	7,830	7,806	7,782	$47,056	$67,190	62,022	5,168
17 Disposal of Noncontainerized Liquid Waste-Capital	4,550	4,520	4,489	4,458	4,427	4,397	$26,841	$38,511	35,549	2,962
20 Wastewater Discharge Elimination and Reuse	17,849	17,795	17,740	17,686	17,632	17,577	$106,279	$151,746	140,073	11,673
21 St. Lucie Turtle Net	0	0	0	3,600	7,194	7,181	$17,975	$17,975	16,592	1,383
2 Total Investment Projects - Recoverable Costs	$ 510,065	$ 508,539	$ 507,012	$ 509,036	$ 511,670	$ 515,643	$ 3,061,965	$ 4,365,048	$ 1,573,952	$ 2,791,096
3 Recoverable Costs Allocated to Energy	$ 327,768	$ 326,643	$ 325,518	$ 324,665	$ 323,860	$ 323,157	$ 1,951,611	$ 2,791,096	$ 4,365,048	
4 Recoverable Costs Allocated to Demand	$ 182,297	$ 181,896	$ 181,494	$ 184,371	$ 187,810	$ 192,486	$ 1,110,354	$ 1,573,952	$ 4,365,048	
5 *Retail Energy Jurisdictional Factor*	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%				
6 Retail Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 324,365	$ 323,251	$ 322,137	$ 321,294	$ 320,497	$ 319,801	$ 1,931,346	$ 2,762,114		
8 Jurisdictional Demand Recoverable Costs (C)	$ 180,539	$ 180,142	$ 179,745	$ 182,593	$ 186,000	$ 190,631	$ 1,099,650	$ 1,558,779		
9 Total Jurisdictional Recoverable Costs for Investment Projects	$ 504,904	$ 503,394	$ 501,882	$ 503,887	$ 506,497	$ 510,432	$ 3,030,996	$ 4,320,893		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3.	Less: Accumulated Depreciation (B)	7,974,043	8,086,134	8,198,226	8,310,318	8,422,410	8,534,502	8,646,593	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,637,425	$9,525,334	$9,413,242	$9,301,150	$9,189,058	$9,076,966	$8,964,875	n/a
6.	Average Net Investment		9,581,380	9,469,288	9,357,196	9,245,104	9,133,012	9,020,920	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		56,785	56,121	55,456	54,792	54,128	53,463	330,745
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,337	20,099	19,861	19,624	19,386	19,148	118,455
8.	Investment Expenses								
	a. Depreciation (D)		112,092	112,092	112,092	112,092	112,092	112,092	672,551
	b. Amortization								
	c Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$189,214	$188,312	$187,410	$186,507	$185,605	$184,703	$1,121,751

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month acti
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3.	Less: Accumulated Depreciation (B)	8,646,593	8,758,685	8,870,777	8,982,869	9,094,961	9,207,053	9,319,144	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$8,964,875	$8,852,783	$8,740,691	$8,628,599	$8,516,507	$8,404,415	$8,292,324	n/a
6.	Average Net Investment		8,908,829	8,796,737	8,684,645	8,572,553	8,460,461	8,348,370	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		52,799	52,135	51,470	50,806	50,142	49,477	637,575
	b. Debt Component (Line 6 x 2.5471% x 1/12)		18,910	18,672	18,434	18,196	17,958	17,720	228,344
8.	Investment Expenses								
	a. Depreciation (D)		112,092	112,092	112,092	112,092	112,092	112,092	1,345,102
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$183,801	$182,898	$181,996	$181,094	$180,192	$179,289	$2,211,021

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month acti
(E) In June and July depreciation expense of $28,528.50 was inadvertently omitted from the Low Nox total. This error was corrected in August ($28,258.50 x 2 = $57,057)

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$44	$4,310	$5,294	($7,267)		$0	$2,380
	c. Retirements				$1,946,624	$5,718		$16,321	
	d. Other (A)					$1,923			
2.	Plant-In-Service/Depreciation Base	$14,961,390	14,961,434	14,965,743	13,024,413	13,011,428	13,011,428	12,995,106	0
3.	Less: Accumulated Depreciation (B)	5,183,308	5,257,914	5,332,532	3,336,898	3,396,151	3,462,993	3,513,475	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,778,082	$9,703,520	$9,633,211	$9,687,515	$9,615,276	$9,548,435	$9,481,631	n/a
6.	Average Net Investment		9,740,801	9,668,365	9,660,363	9,651,396	9,581,856	9,515,033	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		57,730	57,301	57,253	57,200	56,788	56,392	342,663
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,676	20,522	20,505	20,486	20,338	20,196	122,723
8.	Investment Expenses								
	a. Depreciation (D)		74,606	74,618	(49,010)	66,895	66,841	66,804	300,754
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$153,012	$152,440	$28,748	$144,580	$143,967	$143,392	$766,140

Notes:
(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$2,380
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$12,995,106	12,995,106	12,995,106	12,995,106	12,995,106	12,995,106	12,995,106	n/a
3.	Less: Accumulated Depreciation (B)	3,513,476	3,580,241	3,647,008	3,713,774	3,780,540	3,847,307	3,914,073	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,481,631	$9,414,865	$9,348,099	$9,281,332	$9,214,566	$9,147,800	$9,081,034	n/a
6.	Average Net Investment		9,448,248	9,381,482	9,314,716	9,247,949	9,181,183	9,114,417	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		55,996	55,600	55,205	54,809	54,413	54,018	672,704
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,055	19,913	19,771	19,630	19,488	19,346	240,926
8.	Investment Expenses								
	a. Depreciation (D)		66,766	66,766	66,766	66,766	66,766	66,766	701,352
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$142,817	$142,280	$141,742	$141,205	$140,667	$140,130	$1,614,981

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (B)	20,950	21,194	21,439	21,683	21,927	22,172	22,416	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$37,916	$37,672	$37,427	$37,183	$36,939	$36,694	$36,450	n/a
6.	Average Net Investment		37,794	37,550	37,305	37,061	36,817	36,572	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		224	223	221	220	218	217	1,322
	b. Debt Component (Line 6 x 2.5471% x 1/12)		80	80	79	79	78	78	474
8.	Investment Expenses								
	a. Depreciation (D)		244	244	244	244	244	244	1,466
	b. Amortization								
	c Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$549	$547	$545	$543	$541	$539	$3,264

Notes:
(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (B)	22,416	22,660	22,905	23,149	23,393	23,638	23,882	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$36,450	$36,206	$35,961	$35,717	$35,473	$35,228	$34,984	n/a
6.	Average Net Investment		36,328	36,084	35,839	35,595	35,351	35,106	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		215	214	212	211	210	208	2,592
	b. Debt Component (Line 6 x 2.5471% x 1/12)		77	77	76	76	75	75	928
8.	Investment Expenses								
	a. Depreciation (D)		244	244	244	244	244	244	2,932
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	*Total System Recoverable Expenses (Lines 7 & 8)*		$537	$535	$533	$531	$529	$527	$6,456

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project. Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$212,601	$221,881	($4)				$434,478
	c. Retirements				$3,404,519				
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$15,630,479	15,843,080	16,064,961	12,660,438	12,660,438	12,660,438	12,660,438	n/a
3.	Less: Accumulated Depreciation (B)	1,522,480	1,565,911	1,610,177	(1,918,889)	(1,881,221)	(1,843,484)	(1,805,683)	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,107,999	$14,277,169	$14,454,784	$14,579,327	$14,541,659	$14,503,922	$14,466,121	n/a
6.	Average Net Investment		14,192,584	14,365,977	14,517,055	14,560,493	14,522,790	14,485,021	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		84,114	85,141	86,037	86,294	86,071	85,847	513,504
	b. Debt Component (Line 6 x 2.5471% x 1/12)		30,125	30,493	30,814	30,906	30,826	30,746	183,909
8.	Investment Expenses								
	a. Depreciation (D)		43,431	44,266	(124,547)	37,668	37,737	37,801	76,356
	b Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$157,670	$159,901	($7,696)	$154,868	$154,634	$154,393	$773,770

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the mont
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior mon
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$860,000	$1,294,478
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$12,660,438	12,660,438	12,660,438	12,660,438	12,660,438	12,660,438	13,520,438	n/a
3	Less. Accumulated Depreciation (B)	(1,805,683)	(1,767,818)	(1,729,954)	(1,692,089)	(1,654,224)	(1,616,359)	(1,576,631)	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,466,121	$14,428,256	$14,390,391	$14,352,527	$14,314,662	$14,276,797	$15,097,069	n/a
6.	Average Net Investment		14,447,189	14,409,324	14,371,459	14,333,594	14,295,729	14,686,933	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		85,623	85,398	85,174	84,950	84,725	87,044	1,026,418
	b. Debt Component (Line 6 x 2 5471% x 1/12)		30,665	30,585	30,505	30,424	30,344	31,174	367,606
8.	Investment Expenses								
	a Depreciation (D)		37,865	37,865	37,865	37,865	37,865	39,728	305,408
	b. Amortization								
	c. Dismantlement								
	d Property Expenses								
	e. Other (E)								
9.	*Total System Recoverable Expenses (Lines 7 & 8)*		$154,153	$153,848	$153,543	$153,239	$152,934	$157,946	$1,699,433

Notes:

(A) N/A
(B) N/A
(C) *The gross-up factor for taxes uses* 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant in Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior mont
(E) To correct depreciation expense for Work Order No 5367/70/913/06 from 1994 to present. A retirement made in 1994 was not removed from the depreciation calculation causing excess depreciation to be calculated.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (B)	11,934	12,086	12,239	12,392	12,544	12,697	12,849	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$19,096	$18,944	$18,791	$18,639	$18,486	$18,333	$18,181	n/a
6.	Average Net Investment		19,020	18,867	18,715	18,562	18,410	18,257	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		113	112	111	110	109	108	663
	b. Debt Component (Line 6 x 2.5471% x 1/12)		40	40	40	39	39	39	237
8.	Investment Expenses								
	a. Depreciation (D)		153	153	153	153	153	153	915
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$306	$304	$303	$302	$301	$300	$1,816

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (B)	12,849	13,002	13,154	13,307	13,459	13,612	13,765	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$18,181	$18,028	$17,876	$17,723	$17,571	$17,418	$17,265	n/a
6.	Average Net Investment		18,105	17,952	17,799	17,647	17,494	17,342	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		107	106	105	105	104	103	1,293
	b. Debt Component (Line 6 x 2.5471% x 1/12)		38	38	38	37	37	37	463
8.	Investment Expenses								
	a. Depreciation (D)		153	153	153	153	153	153	1,831
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$298	$297	$296	$295	$293	$292	$3,587

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements				$3,907				
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$719,530	719,530	719,530	715,623	715,623	715,623	715,623	n/a
3.	Less: Accumulated Depreciation (B)	268,756	276,712	284,668	288,716	296,672	304,628	312,584	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$450,774	$442,818	$434,863	$426,907	$418,951	$410,995	$403,039	n/a
6.	Average Net Investment		446,796	438,841	430,885	422,929	414,973	407,017	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		2,648	2,601	2,554	2,507	2,459	2,412	15,181
	b. Debt Component (Line 6 x 2.5471% x 1/12)		948	931	915	898	881	864	5,437
8.	Investment Expenses								
	a. Depreciation (D)		7,956	7,956	7,956	7,956	7,956	7,956	47,735
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,552	$11,488	$11,424	$11,360	$11,296	$11,232	$68,352

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$5,041	$0	$0	$61,959	$0	$67,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$715,623	715,623	720,664	720,664	720,664	782,623	782,623	n/a
3.	Less: Accumulated Depreciation (B)	312,584	320,540	328,525	336,541	344,557	352,942	361,326	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$403,039	$395,084	$392,139	$384,123	$376,107	$429,681	$421,297	n/a
6.	Average Net Investment		399,061	393,611	388,131	380,115	402,894	425,489	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		2,365	2,333	2,300	2,253	2,388	2,522	29,341
	b. Debt Component (Line 6 x 2.5471% x 1/12)		847	835	824	807	855	903	10,508
8.	Investment Expenses								
	a Depreciation (D)		7,956	7,986	8,016	8,016	8,385	8,385	96,478
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,168	$11,154	$11,140	$11,075	$11,628	$11,809	$136,326

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (B)	26,997	27,312	27,626	27,940	28,254	28,568	28,882	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$90,797	$90,482	$90,168	$89,854	$89,540	$89,226	$88,912	n/a
6.	Average Net Investment		90,639	90,325	90,011	89,697	89,383	89,069	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		537	535	533	532	530	528	3,195
	b. Debt Component (Line 6 x 2.5471% x 1/12)		192	192	191	190	190	189	1,144
8.	Investment Expenses								
	a. Depreciation (D)		314	314	314	314	314	314	1,885
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,044	$1,041	$1,039	$1,036	$1,034	$1,031	$6,225

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (B)	28,882	29,196	29,510	29,824	30,139	30,453	30,767	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$88,912	$88,598	$88,284	$87,970	$87,655	$87,341	$87,027	n/a
6.	Average Net Investment		88,755	88,441	88,127	87,812	87,498	87,184	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		526	524	522	520	519	517	6,323
	b. Debt Component (Line 6 x 2.5471% x 1/12)		188	188	187	186	186	185	2,265
8.	Investment Expenses								
	a. Depreciation (D)		314	314	314	314	314	314	3,769
	b. Amortization								
	c. Dismantlement								
	d Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,029	$1,026	$1,023	$1,021	$1,018	$1,016	$12,358

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month.
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (B)	238,961	241,990	245,019	248,048	251,077	254,106	257,134	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$625,299	$622,270	$619,241	$616,212	$613,183	$610,154	$607,126	n/a
6.	Average Net Investment		623,785	620,756	617,727	614,698	611,669	608,640	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		3,697	3,679	3,661	3,643	3,625	3,607	21,912
	b. Debt Component (Line 6 x 2.5471% x 1/12)		1,324	1,318	1,311	1,305	1,298	1,292	7,848
8.	Investment Expenses								
	a. Depreciation (D)		3,029	3,029	3,029	3,029	3,029	3,029	18,173
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,050	$8,025	$8,001	$7,977	$7,952	$7,928	$47,933

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (B)	257,134	260,163	263,192	266,221	269,250	272,279	275,308	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$607,126	$604,097	$601,068	$598,039	$595,010	$591,981	$588,952	n/a
6.	Average Net Investment		605,611	602,582	599,553	596,524	593,496	590,467	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		3,589	3,571	3,553	3,535	3,517	3,499	43,178
	b. Debt Component (Line 6 x 2.5471% x 1/12)		1,285	1,279	1,273	1,266	1,260	1,253	15,464
8.	Investment Expenses								
	a. Depreciation (D)		3,029	3,029	3,029	3,029	3,029	3,029	36,347
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,904	$7,879	$7,855	$7,830	$7,806	$7,782	$94,989

Notes:

(A) N/A

(B) N/A

(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.

(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity

(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$694,142	$0	$0	$694,142
	c. Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$0	0	0	0	694,142	694,142	694,142	n/a
3.	Less: Accumulated Depreciation (B)	0	0	0	0	810	2,429	4,049	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$693,332	$691,712	$690,093	n/a
6.	Average Net Investment		0	0	0	346,666	692,522	690,903	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		0	0	0	2,055	4,104	4,095	10,254
	b. Debt Component (Line 6 x 2.5471% x 1/12)		0	0	0	736	1,470	1,466	3,672
8.	Investment Expenses								
	a. Depreciation (D)		0	0	0	810	1,620	1,620	4,049
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$3,600	$7,194	$7,181	$17,975

Notes:
(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4 3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant in Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d Other (A)								
2.	Plant-In-Service/Depreciation Base	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less: Accumulated Depreciation (B)	195,425	199,245	203,065	206,885	210,705	214,525	218,345	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$115,584	$111,764	$107,944	$104,124	$100,304	$96,484	$92,664	n/a
6.	Average Net Investment		113,674	109,854	106,034	102,214	98,394	94,574	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		674	651	628	606	583	561	3,703
	b. Debt Component (Line 6 x 2.5471% x 1/12)		241	233	225	217	209	201	1,326
8.	Investment Expenses								
	a. Depreciation (D)		3,820	3,820	3,820	3,820	3,820	3,820	22,920
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,735	$4,704	$4,673	$4,643	$4,612	$4,581	$27,948

Notes:
(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less: Accumulated Depreciation (B)	218,345	222,164	225,984	229,804	233,624	237,444	241,264	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$92,664	$88,845	$85,025	$81,205	$77,385	$73,565	$69,745	n/a
6.	Average Net Investment		90,755	86,935	83,115	79,295	75,475	71,655	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		538	515	493	470	447	425	6,590
	b. Debt Component (Line 6 x 2.5471% x 1/12)		193	185	176	168	160	152	2,360
8.	Investment Expenses								
	a. Depreciation (D)		3,820	3,820	3,820	3,820	3,820	3,820	45,840
	b. Amortization								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,550	$4,520	$4,489	$4,458	$4,427	$4,397	$54,789

Notes:
(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates. Half month depreciation is calculated on additions closing to Plant In Service during the month. Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing. Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/Stormwater Reuse (Project No. 20)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1	Investments								
	a Expenditures/Additions								
	b Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c Retirements								
	d. Other (A)								
2	Plant-In-Service/Depreciation Base	$1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	n/a
3	Less. Accumulated Depreciation (B)	141,111	147,860	154,609	161,358	168,107	174,856	181,605	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,422,884	$1,416,135	$1,409,386	$1,402,637	$1,395,888	$1,389,139	$1,382,390	n/a
6.	Average Net Investment		1,419,510	1,412,761	1,406,012	1,399,263	1,392,514	1,385,765	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (C)		8,413	8,373	8,333	8,293	8,253	8,213	49,877
	b Debt Component (Line 6 x 2 5471% x 1/12)		3,013	2,999	2,984	2,970	2,956	2,941	17,863
8.	Investment Expenses								
	a Depreciation (D)		6,749	6,749	6,749	6,749	6,749	6,749	40,494
	b. Amortization								
	c Dismantlement								
	d. Property Expenses								
	e Other (E)								
9	Total System Recoverable Expenses (Lines 7 & 8)		$18,175	$18,121	$18,066	$18,012	$17,958	$17,903	$108,235

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0 61425, which reflects the Federal Income Tax Rate of 35%, the monthly Equity Component of 4 3685% reflects a 11% return on equity
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month
Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity.
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments. Depreciation and Taxes
For Project. Wastewater/Stormwater Reuse (Project No. 20)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1	Investments								
	a Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c Retirements								
	d Other (A)								
2	Plant-In-Service/Depreciation Base	$1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	1,563,995	n/a
3.	Less: Accumulated Depreciation (B)	$181,605	188,354	195,103	201,852	208,601	215,350	222,099	n/a
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,382,390	$1,375,641	$1,368,892	$1,362,143	$1,355,394	$1,348,645	$1,341,896	n/a
6	Average Net Investment		1,379,016	1,372,266	1,365,517	1,358,768	1,352,019	1,345,270	
7	Return on Average Net Investment								
	Equity Component grossed up for taxes (C)		8,173	8,133	8,093	8,053	8,013	7,973	98,315
	Debt Component (Line 6 x 2 5471% x 1/12)		2,927	2,913	2,898	2,884	2,870	2,855	35,211
8	Investment Expenses								
	a Depreciation (D)		6,749	6,749	6,749	6,749	6,749	6,749	80,988
	b Amortization								
	c. Dismantlement								
	d Property Expenses								
	e Other (E)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$17,849	$17,795	$17,740	$17,686	$17,632	$17,577	$214,514

Notes:

(A) N/A
(B) N/A
(C) The gross-up factor for taxes uses 0 61425, which reflects the Federal Income Tax Rate of 35%, the monthly Equity Component of 4 3685% reflects a 11% return on equity.
(D) Depreciation expense is calculated using the appropriate site and account rates Half month depreciation is calculated on additions closing to Plant In Service during the month Depreciation and return are calculated and recorded on a one month lag due to the timing of the month end closing Amounts recorded and shown above apply to prior month activity
(E) N/A

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(1,538,080)	(1,519,063)	(1,500,047)	(1,481,031)	(1,462,015)	(1,750,340)	(1,765,960)		
2	Total Working Capital	($1,538,080)	($1,519,063)	($1,500,047)	($1,481,031)	($1,462,015)	($1,750,340)	($1,765,960)		
3	Average Net Working Capital Balance		(1,528,571)	(1,509,555)	(1,490,539)	(1,471,523)	(1,606,177)	(1,758,150)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(9,059)	(8,947)	(8,834)	(8,721)	(9,519)	(10,420)	(55,500)	
b	Debt Component (Line 3 x 2.5471% x 1/12)		(3,245)	(3,204)	(3,164)	(3,123)	(3,409)	(3,732)	(19,877)	
5	Total Return Component		($12,304)	($12,151)	($11,998)	($11,845)	($12,928)	($14,152)	($75,377)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(19,016)	(19,016)	(19,016)	(19,016)	(139,880)	(43,189)	(259,134)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
c	509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($19,016)	($19,016)	($19,016)	($19,016)	($139,880)	($43,189)	($259,134)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(31,320)	(31,167)	(31,014)	(30,861)	(152,809)	(57,341)		
a	Recoverable Costs Allocated to Energy		(31,320)	(31,167)	(31,014)	(30,861)	(152,809)	(57,341)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53755%	98.53755%	98.53755%	98.53755%	98.53755%	98.53755%		
10	Demand Jurisdictional Factor		97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%		
11	Retail Energy-Related Recoverable Costs (B)		(30,862)	(30,711)	(30,560)	(30,410)	(150,574)	(56,502)	(329,619)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($30,862)	($30,711)	($30,560)	($30,410)	($150,574)	($56,502)	($329,619)	

Notes:

(A) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	End of Period Amount
1	Working Capital Dr (Cr)								
	a 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	
	b 158.200 Allowances Withheld	0	0	0	0	0	0	0	
	c 182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0	
	d 254.900 Other Regulatory Liabilities-Gains	(1,765,960)	(1,722,771)	(1,679,582)	(1,636,393)	(1,593,204)	(1,550,015)	(1,506,826)	
2	Total Working Capital	($1,765,960)	($1,722,771)	($1,679,582)	($1,636,393)	($1,593,204)	($1,550,015)	($1,506,826)	
3	Average Net Working Capital Balance		(1,744,366)	(1,701,177)	(1,657,988)	(1,614,798)	(1,571,609)	(1,528,420)	
4	Return on Average Net Working Capital Balance								
	a Equity Component grossed up for taxes (A)		(10,338)	(10,082)	(9,826)	(9,570)	(9,314)	(9,058)	(113,689)
	b Debt Component (Line 6 x 2 5471% x 1/12)		(3,703)	(3,611)	(3,519)	(3,428)	(3,336)	(3,244)	(40,717)
5	Total Return Component		($14,041)	($13,693)	($13,345)	($12,998)	($12,650)	($12,303)	($154,407)
6	Expense Dr (Cr)								
	a 411.800 Gains from Dispositions of Allowances		(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(43,189)	(518,269)
	b 411 900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-
	c 509 000 Allowance Expense		0	0	0	0	0	0	-
7	Net Expense (Lines 6a+6b+6c)		($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($43,189)	($518,269)
8	Total System Recoverable Expenses (Lines 5+7)		($57,230)	($56,882)	($56,535)	($56,187)	($55,839)	($55,492)	
	a Recoverable Costs Allocated to Energy		(57,230)	(56,882)	(56,535)	(56,187)	(55,839)	(55,492)	
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.53755%	98.53755%	98 53755%	98 53755%	98.53755%	98 53755%	
10	Demand Jurisdictional Factor		97.87297%	97 87297%	97.87297%	97.87297%	97.87297%	97.87297%	
11	Retail Energy-Related Recoverable Costs (B)		(56,393)	(56,050)	(55,708)	(55,365)	(55,023)	(54,680)	(662,838)
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($56,393)	($56,050)	($55,708)	($55,365)	($55,023)	($54,680)	($662,838)

Notes:
(A) The gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects a 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
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In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability

Totals may not add due to rounding.

DOCUMENT I

U.S. Department Of Transportation
Regulation 49 CFR Part 195

RRL-1
DOCKET NO. 020007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT ______
PAGES 1-10

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA-00-7408; Amdt. No. 195-76]

RIN 2137-AD49

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines)

AGENCY: Research and Special Programs Administration (RSPA), U.S. Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: Our regulations for the transportation of hazardous liquids by pipeline require operators with 500 or more miles of regulated pipelines to establish a program for managing the integrity of pipelines that affect high consequence areas. The regulations require continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventive, and mitigative actions. This Final Rule extends those regulations to operators with less than 500 miles of regulated pipelines. We are taking this action because safety recommendations, statutory mandates, and accident analyses indicate that coordinated risk control measures are needed for public safety and environmental protection in addition to compliance with traditional safety standards. Broadening the coverage of the existing regulations will further enhance the protection of high consequence areas against the risk of pipeline failures.

DATES: This Final Rule takes effect February 15, 2002.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202-366-4559, by fax at 202-366-4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at *buck.furrow@rspa.dot.gov*.

SUPPLEMENTARY INFORMATION:

Background

Last year we amended the regulations in 49 CFR part 195 to require each operator who owns or operates 500 or more miles of pipelines subject to part 195 to establish a program for managing the integrity of pipelines that could affect a high consequence area if a leak or rupture occurs (Docket No. RSPA-99-6355; 65 FR 75377; Dec. 1, 2000). High consequence areas include highly populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways (§ 195.450). Program standards require continual assessment, evaluation, correction, and validation of pipeline integrity (§ 195.452 and appendix C to part 195). The new standards took effect May 29, 2001 (66 FR 9532; Feb. 8, 2001). In addition, in a further rulemaking action (Docket No. RSPA-99-6355), we are revising the repair provisions of § 195.452(h) and clarifying that § 195.452 applies to carbon dioxide pipelines as well as hazardous liquid pipelines.

We did not apply the new program standards to pipelines of operators with less than 500 miles of regulated pipelines primarily because we needed more information about the potential impact of the standards on these operators. We subsequently learned that these operators include, to a large extent, companies with ample resources and capabilities to carry out the standards.

A wide range of persons who submitted comments to Docket No. RSPA-99-6355 supported the need to apply the new program standards to all operators of regulated pipelines that could affect high consequence areas. Based on these comments and the impact information we had collected, we published a Notice of Proposed Rulemaking (NPRM) to extend the program standards to pipelines of operators with less than 500 miles of regulated pipelines (66 FR 15821; March 21, 2001).

The NPRM did not propose any substantive change to the existing program standards. It merely proposed to establish later deadlines for developing programs under § 195.452(b)(1), identifying pipelines under § 195.452(b)(1)(i), completing baseline assessments under § 195.452(d)(1), accepting prior assessments under § 195.452(b)(2), and applying certain time limits on reviewing assessment results under § 195.452(h)(3). We invited interested persons to submit written comments on the proposed rules until May 21, 2001.

Although the NPRM proposed no substantive change to the program standards, in the earlier proceeding (Docket No. RSPA-99-6355), we invited comments until March 31, 2001, on the substance of the standard for remedial action (§ 195.452(h)). As indicated in the NPRM, if § 195.452(h) is changed in that proceeding, the changes will apply to all operators of pipelines to which the program standards apply, including operators covered by the present Final Rule.

Disposition of Comments

This section of the preamble summarizes written comments we received in response to the NPRM. It also describes how we treated those comments in developing the final rules. However, comments related to costs and benefits and the impact of the proposed rules on small entities are addressed in the "Regulatory Analyses and Notices" section of this preamble. If a proposed rule is not mentioned, no significant comments were received on the proposal, and we are adopting the proposed rule as final.

Eight persons submitted comments: a professional organization, the American Society of Safety Engineers (ASSE); a state pipeline safety agency, the Washington Utilities and Transportation Commission (WUTC); a Washington State advisory committee, the Citizens Advisory Committee on Pipeline Safety (CAC); the Small Business Administration (SBA); the Department of Energy (DOE); an engineering firm, Wink, Incorporated (Wink); and two pipeline operators, the Laclede Pipeline Company (Laclede) and the Tosco Corporation (Tosco). ASSE did not comment on specific proposals in the NPRM, but strongly supported our goal of assuring the integrity of pipeline systems. ASSE also said improving pipeline safety would improve the United States' competitive position in the world economy. WUTC, CAC, Tosco, and DOE expressed general support for the NPRM but, along with Wink, suggested changes. DOE also commented on the costs of the proposed rules in their impact on small entities. Laclede opposed the integrity assessment proposal and took issue with our estimate of compliance costs. SBA's comments were limited to the impact of the proposed rules on small entities.

Under proposed §§ 195.452(b)(1) and (b)(1)(i), operators with less than 500 miles of pipelines would have 9 months after the effective date of the final rules to identify all pipeline segments that could affect high consequence areas. They would have 1 year after the effective date to develop a written integrity management program that addresses the risks of those segments. Tosco said the identification of pipeline segments should occur after, not before, integrity management programs are completed, and suggested we allow operators 1 year to complete the identifications. In considering this comment, we noted that operators with 500 or more miles of pipelines have not indicated they expect any significant difficulties in meeting the 9-month identification rule. Tosco's comment does not give us reason to believe the 9-month rule might be too burdensome for operators with less than 500 miles of pipelines. While Tosco is correct that operators will need to have relevant program elements in place to guide them in identifying pipeline segments, we believe 9 months is enough time to complete those elements and to carry out the identifications. The additional 3 months the existing rule provides for program development gives operators enough time to complete program elements other than those concerning identification. We do not think this additional time is also needed to identify pipeline segments.

CAC suggested we require operators to seek input from potentially affected communities in identifying high consequence areas. CAC believed the input would help operators identify areas of population at risk and areas of economic importance. Although we recognize community input is valuable in many situations involving pipelines, particularly in site selection and emergency response, we do not feel it is necessary to mandate that operators seek the input CAC envisioned for two reasons. First, the definition of "high consequence area" in § 195.450 covers CAC's concern about the population-at-risk. That definition refers to areas of high or concentrated population that the U.S. Census Bureau has defined and delineated. Operators should be able to identify these areas quite easily using Census Bureau data. If additional information is needed from community records to complete the identifications, the proposed rule would implicitly obligate operators to seek this information, making an explicit requirement unnecessary. Secondly, the NPRM did not propose to require integrity management of pipelines that could affect areas of economic significance other than commercially navigable waterways. These waterways, which operators also can readily identify without community input, arguably are the nation's foremost economic resources potentially at risk from pipeline spills. Other significant economic resources that may be affected by pipelines are less certain, and we feel the present regulations in Part 195 provide those resources adequate protection against the risk of pipeline spills. Similarly, in directing DOT to require additional inspection of certain pipelines, Congress did not include pipelines that affect economic resources other than commercially navigable waterways (49 U.S.C. 60102(f)(2) and 60109). If in the future there is a need to apply the integrity management rules to pipelines affecting other significant economic resources, we will consider whether operators should seek community input in identifying those resources.

Although we did not adopt CAC's recommendations, it is important to note that in a separate proceeding we are considering the need for regulations on better communication of pipeline information by operators to local officials and the public. We have formed a communications work team, consisting of representatives from environmental and public safety organizations, pipeline companies, and government to aid our own hazardous liquid pipeline safety advisory committee in examining communications issues. Notices of meetings of the work group are published in the **Federal Register**, and minutes of the meetings are posted on this Web site: *http://ops.dot.gov*.

WUTC suggested we require baseline integrity assessments of new pipelines as soon after they are constructed as possible, and for existing pipelines as soon as practicable after the final rules take effect. WUTC stated that early baseline assessment would provide the best basis for comparing subsequent assessment results. The NPRM proposed, in § 195.452(d), that operators with less than 500 miles of pipeline complete baseline assessments within 7 years after the effective date of the final rule, with half the line pipe, selected by risk, assessed within 42 months after the effective date. Alternatively, operators could use as a baseline assessment any qualified integrity assessment completed within the 5 years prior to the effective date. For newly constructed pipelines, hydrostatic testing completed as required by other regulations in Part 195 will fulfill the baseline assessment requirement. Since this testing is normally part of the construction process, it should meet WUTC's objective of early assessment. For existing pipelines, we proposed 7 years to complete baseline assessments because of the volume of assessments, the limited availability of in-line inspection tools, and the time needed to schedule pressure testing to minimize service disruptions. Although we agree with WUTC that earlier baseline assessment would be beneficial, we do not think requiring earlier baseline assessments would be reasonable under present circumstances.

To assure that only qualified persons develop integrity management programs and make program decisions, Wink suggested we require operators to use, registered professional engineers with demonstrated technical pipeline expertise and experience. Wink further suggested we require operators to submit their integrity management programs for review by RSPA certified entities. We did not adopt either suggestion because to do so would go beyond the scope of the NPRM. While § 195.452(f)(8) requires operators to use persons qualified to evaluate assessment results and analyze information, the NPRM did not address specific qualifications or program review by certified entities. Based on our experience in other areas of pipeline regulation, we believe operators will use qualified engineers with pipeline experience to assist in developing integrity management programs and recommend critical decisions under the programs. Moreover, persons carrying out regulated assessment and mitigation activities on pipelines are subject to the existing qualification requirements in Subpart G of Part 195. To assure that operators carry out their programs in accordance with the rules, we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. This type of evaluative process has been satisfactory for other programs and plans required by Part 195. We prefer to continue this approach to assure the quality of integrity management programs rather than establish additional personnel qualifications or a new federal certification program.

Wink asked to what extent operators would have to consider potential terrorist activities in their ongoing assessments of pipeline integrity. Under one of the integrity management program requirements (§ 195.452(e)(1)), operators must schedule integrity assessments based on "all risk factors that reflect the risk conditions on the pipeline." Therefore, if an operator knows or it is reasonable to anticipate that there is a threat to the integrity of the pipeline from terrorist activity, the operator must consider that risk in developing its integrity program. Since the events of September 11, 2001, we are working with DOT, the Department of Energy, the Federal Energy Regulatory Commission, and State agencies, to consider the need for minimum security standards for critical facilities.

Wink postulated that construction permit timing could interfere with an operator's ability to meet remediation deadlines. Section 195.452(h) deals with this potential problem. Under this rule, if justifiable circumstances preclude an operator from meeting specified repair deadlines, the operator may reasonably extend the repair schedule if it temporarily reduces operating pressure to a safe level or notifies us of the delay in making a permanent repair.

Finally, Wink suggested we establish a program review process in which operators would meet with our technical specialists to examine whether the program meets applicable requirements. In response to Wink's first comment, we mentioned we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. We expect this review process will involve meeting with operators' representatives.

Laclede, who operates a 28-mile propane pipeline serving a gas distribution system, believed it would be unreasonable to apply the proposed integrity assessment requirement (§ 195.452(c)) to its pipeline. Laclede said the design of 70 percent of its pipeline cannot accommodate internal inspection tools, and difficulties in de-watering the line after hydrostatic testing would cause control valve and instrument freeze-ups during critical cold weather periods. Laclede suggested we exempt from internal inspection or hydrostatic testing requirements all pipelines directly serving gas distribution systems if the pipeline is cathodically protected and inspected according to our standards or is equipped with emergency flow restricting or shutdown devices. We did not adopt this comment because providing adequate cathodic protection and meeting current inspection requirements cannot assure a pipeline is free from all potentially harmful defects that internal inspection or hydrostatic testing can disclose, such as mechanical damage or fatigue cracks. Also, while emergency flow restricting or shutdown devices are useful in mitigating the consequences of a pipeline rupture, these devices do nothing to prevent ruptures, which is the purpose of periodic internal inspection or hydrostatic testing. Laclede's comment did not fully explain the particular difficulties in de-watering, or drying, its pipeline after hydrostatic testing. Drying pipelines is not an uncommon problem in the industry and not one we believe makes the proposed testing rule unreasonable. Many companies are available to provide expert drying services, using techniques that depend on operating conditions. However, if an operator's circumstances are so unusual that hydrostatic testing would result in unavoidable damage to pipeline facilities and internal inspection is not a viable alternative, the operator may apply for a waiver of the testing requirement as permitted by 49 U.S.C. 60118.

DOE was concerned that construction of new pipelines within the next few years to meet the growing demand for fossil fuels could tax available technical expertise and equipment needed to meet various assessment deadlines in the existing and proposed rules. DOE said available resources could be stretched to a point where meeting the deadlines would not be possible, or at least not possible without significantly increased costs. Therefore, DOE suggested we expand the present provisions for extending deadlines (*e.g.*, § 195.452(j)(4)) to include situations in which meeting a deadline would result in supply disruptions. We agree that by shifting resources away from new construction or shutting down vital pipelines for hydrostatic testing or repair, supply disruptions could occur. However, at this stage we believe the impact of such an eventuality is too speculative to warrant changing the rules to add supply disruption as an acceptable reason for extending deadlines. Also, over the next few years new technologies might become available that would enable acceptable integrity assessments with no effect on supply. If in the future a supply problem appears more likely, the operator involved may petition us for necessary relief or latitude under the rules.

DOE also commented on our plan to identify high consequence areas on it's National Pipeline Mapping System (NPMS) and to make the information available to the public via the Internet. DOE recommended that before implementing this plan, we fully evaluate issues of critical infrastructure protection. Indeed, we designed the NPMS with infrastructure protection issues in mind. For example, to avoid creating a tool for intentional misuse of information with tragic results, critical pipeline components and operating data would not be shown on the NPMS. However, the events of September 11, 2001, have caused even greater concern about the security of critical infrastructure systems. As a result, the NPMS no longer provides open access to pipeline-related data. These data are only available to pipeline operators and local, state, and federal government officials. More information on the availability of data and how operators and officials can access it is on the NPMS home page: http://www.npms.rspa.dot.gov.

Editing Changes

In a further rulemaking action (Docket No. RSPA–99–6355), we are revising § 195.452(h)(3) to eliminate the possibility that periods specified for reviewing integrity assessment results could cause confusion. This change to § 195.452(h)(3) eliminates the need to revise that section to cover operators with less than 500 miles of regulated pipelines. Therefore, this Final Rule does not include the NPRM's proposed change to § 195.452(h)(3).

Because this Final Rule extends the coverage of existing § 195.452 to all operators subject to part 195, there is no need to state in final § 195.452 which operators are subject to § 195.452. Therefore, we edited § 195.452(a) to describe which pipelines are covered by § 195.452 by moving relevant provisions in § 195.452(b)(1) to § 195.452(a). Section 195.452(a) now provides that § 195.452 applies to hazardous liquid and carbon dioxide pipelines that could affect a high consequence area, including pipelines located in a high consequence area unless a risk assessment effectively shows the pipeline could not affect the area.

The NPRM proposed certain compliance dates for covered pipelines that depend on whether the operator of the pipeline owns or operates 500 or more miles of regulated pipelines. Although no one commented on this approach to determining compliance dates, we now recognize the approach could have unintended results. Under the proposed approach, if the miles of regulated pipelines an operator owns or operates changes during the compliance period (through transfer, construction, or abandonment of pipelines), the compliance dates applicable to that operator's covered pipelines could also change. For example, if an operator currently subject to § 195.452 were to reduce its miles of regulated pipelines below 500 during a compliance period for covered pipelines, the operator's covered pipelines would then fall under the later compliance date applicable to operators with less than 500 miles of regulated pipelines. Likewise, covered pipelines of operators who increase their miles of regulated pipelines to 500 or more during a compliance period would become subject to earlier compliance dates. The purpose of the proposed approach to determining compliance dates was merely to establish compliance dates for pipelines covered by the NPRM that are later than the existing compliance dates in § 195.452. We did not intend that the existing or proposed compliance dates change with changes in an operator's regulated pipeline mileage. Rather, we intended to apply the existing and proposed compliance dates to covered pipelines existing on May 29, 2001 (the effective date of existing § 195.452), depending on whether, on that date, the operator owned or operated 500 or more miles of regulated pipelines.

To clarify the application of compliance dates and to eliminate repetitive wording, final § 195.452(a) divides covered pipelines into three categories. The first category includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to part 195. This category of pipelines is subject to the existing compliance dates in § 195.452, and will remain subject to those dates regardless of how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The second category includes pipelines existing on May 29, 2001, that were owned or operated on that date by an operator who owned or operated less than 500 miles of pipeline subject to part 195. This category of pipelines is subject to the later compliance dates proposed in the NPRM for operators with less than 500 miles of regulated pipelines. Like the first category, the compliance dates applicable to the second category of pipelines do not depend on how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The third category of covered pipelines includes pipelines constructed or converted after May 29, 2001. Because these pipelines are not subject to the existing or proposed compliance dates, we have added appropriate dates to §§ 195.452(b)(1), (b)(2)(i), (d)(1), and (h)(3). The dates in paragraphs (b)(1) and (h)(3) provide compliance periods equivalent to periods allowed for Category 1 or 2 pipelines. In paragraph (b)(2)(i), we set the date as the date the pipeline begins operation, because operators should not need any longer time to identify a new or converted pipeline as a covered pipeline. The date the pipeline begins operation is also the compliance date in paragraph (d)(1), because the hydrostatic test part 195 requires on new and converted pipelines before operation will serve as the baseline assessment.

Advisory Committee Consideration

We presented the NPRM for consideration by the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) at a meeting in Washington, DC on August 13, 2001 (66 FR 35505; July 5, 2001). The THLPSSC is RSPA's statutory advisory committee for hazardous liquid pipeline safety. The committee has 15 members, representing industry, government, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. The committee voted unanimously to approve the rules proposed in the NPRM and the associated evaluation of costs and benefits. A transcript of the August 13 meeting is available in Docket No. RSPA–98–4470.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

We consider this Final Rule to be a non-significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4,1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. We do not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034; Feb. 26, 1979).

This section of the preamble summarizes the findings of the Regulatory Evaluation we prepared for this Final Rule. A copy of the Regulatory Evaluation is in the docket.

Pipeline spills can adversely affect human health and the environment. However, the magnitude of this impact differs from area to area. There are some areas in which the impact of a spill will be more significant than it would be in others due to concentrations of people who could be affected or to the presence of environmental resources that are unusually sensitive to damage. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. We are promulgating this Final Rule to afford the necessary additional protection to these high consequence areas.

Last year we established 49 CFR 195.450 and 195.452, which are new requirements for additional protection of populated areas, commercially navigable waterways, and areas unusually sensitive to environmental damage from pipeline spills (65 FR 75377; Dec.1, 2000). The new requirements apply to pipeline operators who own or operate 500 or more miles of pipeline. This Final Rule extends the same requirements, with modified compliance deadlines, to the remaining operators of regulated pipelines—those that own or operate less than 500 miles of regulated pipeline.

RSPA and the National Transportation Safety Board (NTSB) have conducted many investigations that have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations include requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe, and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed DOT to undertake additional pipeline safety measures in areas of potentially high consequence. These statutory requirements call for new regulations on identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters. They also call for new regulations on periodic inspections of pipelines in these areas with internal inspection devices, and on emergency flow restricting devices.

This Final Rule requires operators to systematically manage pipeline integrity to reduce the potential for failures that could affect high consequence areas (populated areas, unusually sensitive areas, and commercially navigable waterways). Operators must develop and follow an integrity management program to identify pipeline segments that could affect high consequence areas, and continually assess, through internal inspection, pressure testing, or equivalent alternative technology, the integrity of those segments. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems, and provide additional protection through preventive and mitigative measures, including the use of emergency flow restricting devices.

Existing §§ 195.450 and 195.452 cover an estimated 86.7 percent of the 157,000 miles of regulated hazardous liquid pipeline in the U.S. This Final Rule covers the remaining 13.3 percent. Of this percentage, we estimate this Final Rule will impact approximately 5,440 miles of pipeline. We estimate the cost to operators to develop the necessary programs at approximately $9.94 million, with an additional annual cost for program upkeep and reporting of $1.32 million. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be updated and improved, as needed.

This Final Rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, or use of other technology capable of equivalent performance. The baseline assessment must be completed within 7 years after this Final Rule goes into effect. After this baseline assessment, the rule further requires that operators periodically reassess and evaluate pipeline segments to ensure their integrity within a 5-year interval. We estimate the cost of periodic reassessment will generally not occur until the sixth year, unless the baseline assessment indicates significant defects that would require earlier reassessment. Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this Final Rule are $6.6 million in the first year and $3.3 million annually thereafter.

This Final Rule requires operators to identify and take preventive or mitigative actions that would enhance public safety or environmental protection, based on a risk analysis of the pipeline segment. One preventive or mitigative action involves installing an emergency flow restricting device on the pipeline segment, if determined necessary. We could not estimate the total cost of installing emergency flow restricting devices because we do not know how many operators will install them. Another action involves evaluating leak detection capability and modifying that capability, if necessary. We do not know how many operators currently have leak detection systems or how many systems will be installed or upgraded as a result of this Final Rule. Therefore, we are unable to estimate the total costs of the leak detection requirements.

As a result of this Final Rule, we expect operators will assess more line pipe than they otherwise would assess. Integrity assessment consists of a baseline assessment, to be conducted within 7 years after the effective date of the final rule, and subsequent reassessment at intervals not to exceed every 5 years. We estimate the cost of additional baseline assessments at approximately $377,000 a year, and the cost of additional reassessments at approximately $531,000 a year. Cost impact will be greater in the sixth and seventh years after the effective date of the final rule due to an overlap between baseline inspection and the initial subsequent inspection. The additional costs in these two years are estimated at $5.26 million.

We cannot easily quantify the benefits of this Final Rule, but we can describe them qualitatively. Issuance of this Final Rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide.

The Final Rule will lead to greater uniformity in how risk is evaluated and addressed. It will also provide more clarity in discussions by government, industry and the public about safety and environmental issues, and how the issues can be resolved.

Section 195.452 is written using a performance-based approach. This approach has several advantages. First, it encourages development and use of new technologies. Secondly, it supports operators' development of more formal, structured risk-based programs. Thirdly, it supports continual evaluation of the programs by RSPA and state inspectors. And lastly, it provides greater opportunity for operators to customize their long-term maintenance programs.

Section 195.452 has stimulated the pipeline industry to develop its own consensus standard using a risk-based approach to integrity management. The rule has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

The Final Rule encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. A balanced program will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways, thus improving industry performance in these areas.

The Final Rule requires a verification process that gives RSPA and state inspectors an opportunity to influence the methods of assessment and the interpretation of results. Government monitoring of the adequacy and implementation of this process should expedite the operators' rates of remedial action and reduce the public's exposure to risk.

A particularly significant benefit of this Final Rule involves the information that operators will gather to support decisions. Two essential elements of the integrity management program are the continual assessment and evaluation of pipeline integrity using inspection and testing technology, and the integration and analysis of all available information about the pipeline. The processes of planning, assessment, and evaluation will provide operators with better data to use in determining a pipeline's condition and the location of potential problems that must be addressed. Also, government inspectors will be able to focus on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures.

The public has expressed concern about the danger pipelines may pose to their neighborhoods. The integrity management process leads to greater accountability to the public for both operators and DOT. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—a visual depiction of pipelines in relation to populated areas, unusually sensitive environmental areas, and commercially navigable waterways. The system integrity requirements will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas.

We have not estimated quantitative benefits for the continual integrity management evaluation required by this Final Rule. We do not believe, however, that requiring this comprehensive process, including the reassessment of pipelines every 5 years, will be an undue burden on operators. We believe the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in high consequence areas are benefit enough to promulgate these requirements.

Laclede commented that we grossly underestimated implementation costs. Laclede notes that our estimate of the cost for all affected operators is $9.64 million, whereas Laclede expects itself to incur costs in excess of $1 million to modify its pipeline. Laclede's estimated costs are to replace piping that can not now be inspected with internal inspection devices. The rule does not require such pipe replacement, and costs for such replacement therefore were not included in the implementation cost estimate. The rule allows use of hydrostatic testing as an alternative to internal inspection. Laclede's replacement of piping to allow passage of internal inspection devices, if undertaken, would be an operational choice based on the company's conclusion that internal inspection would be a better method of assessment than hydrostatic testing. Operators are free to make such operational choices, but they are not required by the rule, and costs associated with pipe replacement are not, therefore, a cost of implementing the rule. We fully considered the costs of hydrostatic testing in the Regulatory Evaluation.

DOE expressed concern that costs associated with shutdown time during assessment or with obtaining permits to conduct repair activities may not have been included in the Regulatory Evaluation. DOE also thought per-mile cost estimates may not be appropriate for operators with only a few miles of pipe. With respect to the impact on small entities, DOE thought the requirements could have an unreasonable impact in some cases.

The values we used to estimate costs for internal inspection and hydrostatic testing were based on detailed studies of both methods that considered all relevant costs. The outcome of those studies are per-mile estimates for conducting assessments. We recognize that costs may be higher for operators that have only a few miles of pipeline, and for whom "fixed" costs of assessment would be amortized over just a few miles. However, we are unable to estimate how many operators may be so affected. Many of the operators subject to this Final Rule are parts of larger companies, as described further in response to Small Business Administration comments, and should not be so affected. We will work with operators who may be unusually impacted, each of whom may request a waiver from particular requirements.

While costs for permitting associated with conducting assessments were included, permitting costs associated with repairs were not estimated. No repair costs were included in the Regulatory Evaluation. This rule does impose time limits on the repair of certain types of defects. Generally, however, repair of conditions that could adversely affect the safe operation of a pipeline is already required by 49 CFR 195.401 and so is not a new requirement in this rule.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), we must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This Final Rule covers only those operators that own or operate less than 500 miles of regulated pipeline. Because of this limitation, only 132 hazardous liquid pipeline operators, covering 13.3 percent of regulated hazardous liquid pipelines, are covered by the Final Rule.

The risks of operating pipelines are similar regardless of the size of the operating company. Accordingly, the need to protect against those risks is also similar, regardless of operator size. We agree with WUTC's comment that "[t]he integrity of the hazardous liquid infrastructure that runs beneath our nation's cities, and crosses our public and private lands, should not be treated differently depending on the amount of pipeline owned or operated by pipeline companies."

We established an artificial cutoff criterion of 500 miles specifically so that we could review further the potential impact and safety needs of smaller operators to see if different treatment was needed. We completed our review and concluded that different treatment was not needed. By this Final Rule, we are establishing the same integrity management requirements for operators with less than 500 miles of pipelines as we established previously for operators with more pipeline mileage. Extending the existing requirements to the remaining operators of regulated pipelines is necessary to ensure the integrity of pipelines which could, if damaged or ruptured, cause significant injury to public safety and the environment.

We preliminarily concluded that there is no disproportionate impact on small businesses, principally because the risks are the same. We examined the companies that operate less than 500 miles of pipelines. A few of these operators are "small businesses" (less than 1500 employees, the Small Business Administration's criterion for defining a small business in the hazardous liquid pipeline industry.) The majority, however, is not. The majority includes larger companies or divisions or subsidiaries of very large national and multi-national companies.

We estimate that 132 operators are potentially subject to the requirements of this Final Rule, because that is the number of operators who paid user fees on less than 500 miles of pipeline in the last fiscal year. This number is a conservative upper bound. Some of these operators are not, in fact, affected by this rulemaking. As noted above, many are divisions or subsidiaries of larger companies. In many cases, the parent companies have other divisions or subsidiaries that operate pipelines and, when all are considered, own or operate more than 500 miles of such pipeline. Those companies, including all their divisions and subsidiaries which may, themselves, operate less than 500 miles of pipeline, are covered by existing § 195.452 and not by this Final Rule. In addition, this Final Rule only covers pipeline segments that could affect a high consequence area. It is possible that some operators, particularly those with only a few miles of pipe, may not operate any segments that could affect such areas. If so, those operators would not be covered by this Final Rule. Nevertheless, we continue to estimate costs on the basis of 132 covered companies, in order to provide a conservative estimate.

SBA thought the NPRM's discussion of the Regulatory Flexibility Act was inadequate. The discussion did not include background and basis information that was in the previous rulemaking applicable to operators with 500 or more miles of regulated pipeline. However, in the present document we have improved our discussion of Regulatory Flexibility Act issues to describe more clearly the basis for concluding that this Final Rule does not disproportionately affect small businesses. SBA's comments are also discussed in detail in the final Regulatory Evaluation, included in the docket.

Therefore, based on the facts available about the anticipated impacts of this rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this Final Rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This Final Rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), we have submitted a copy of the Paperwork Reduction Act Analysis to the OMB for review. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas for Operators with less than 500 miles of pipeline." The purpose of this information collection is designed to require operators of pipelines to develop a program to provide direct integrity testing and evaluation of pipelines in high consequence areas.

No comment submitted in response to the NPRM addressed the information collection requirements.

One hundred and thirty-two operators of hazardous liquid pipelines will be potentially subject to this Final Rule. We estimate that those operators will have to develop integrity management programs taking approximately 2,800 hours per program. Each of the operators will also have to devote 1,000 hours in the first year to integrate data into current management information systems.

Additionally, under this Final Rule, operators will have to update their integrity management programs on a continual basis. We estimate updates will take approximately 330 hours per program, annually. An additional 500 hours per operator is estimated for the requirement to annually integrate data into the operator's current management information systems.

Under the Final Rule, operators may use either hydrostatic testing or an internal inspection tool as a method to assess their pipelines. However, operators may use another technology if they can demonstrate it provides an equivalent understanding of the condition of the line pipe as the other two assessment methods. Operators have to provide RSPA 90-days notice (by mail or facsimile) before using the other technology. We believe that few operators will choose this option. If they do choose an alternative technology, notice preparation should take approximately 1 hour. Because we believe few if any operators will elect to use other technologies, the burden was considered minimal and therefore not calculated.

Additionally, the Final Rule allows operators in particular situations to vary from the 5-year continual reassessment interval or repair schedule if they can provide the necessary justification and supporting documentation. Advance notice would have to be provided to RSPA if an operator does so. The advance notification can be in the form of letter or fax. We believe the burden of a letter or fax is minimal and therefore did not add it to the overall burden hours discussed above.

Organizations and individuals desiring to submit comments on the information collection should direct them to: The Office of Management and Budget, Office of Information and Regulatory Affairs, ATTN: RSPA Desk Officer, 727 Jackson Place, NW, Washington, DC 20503. Please provide the docket number of this action. Comments must be sent within 30 days of the publication of this Final Rule.

OMB is specifically interested in the following issues concerning the information collection:

1. Evaluating whether the collection is necessary for the proper performance of the functions of DOT, including whether the information would have a practical use;

2. Evaluating the accuracy of DOT's estimate of the burden of the collection of information, including the validity of assumptions used;

3. Enhancing the quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology; *e.g.*, permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The OMB control number for this information collection is 2137–0605.

Executive Order 13084

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments"). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This Final Rule does not adopt any regulation that: (1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on state and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255, Aug. 10, 1999) do not apply. In a public meeting we held on November 18–19, 1999, we invited the National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, we held conference calls with NAPSR, to receive its input before proposing an integrity management rule.

Impact on Business Processes and Computer Systems

We do not want to impose new requirements that would mandate business process changes when the resources necessary to implement those requirements would otherwise be applied to "Y2K" or related computer problems. This Final Rule does not mandate business process changes or require modifications to computer systems. Because the final rules will not affect the ability of organizations to respond to those problems, we are not delaying the effectiveness of the requirements.

Unfunded Mandates Reform Act of 1995

This Final Rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either state, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the NPRM.

National Environmental Policy Act

We have analyzed the Final Rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT Order 5610.1D. We have determined that this action will not significantly affect the quality of the human environment.

The Environmental Assessment (available in the Docket) determined that the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the Final Rule. The following discussion summarizes the analysis provided in the Environmental Assessment.

Many operators covered by the Final Rule (those operating less than 500 miles of regulated pipeline) already have internal inspection and pressure testing programs that cover most, if not all, of their pipeline systems. These operators typically place a high priority on the pipeline's proximity to populated areas, commercially navigable waterways, and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, some high consequence areas have already been recently assessed, and a large fraction of remaining locations would probably have been assessed in the next several years without the Final Rule. The most tangible impact will be to ensure assessments are performed for those line segments that could affect a high consequence area that are not currently being internally inspected or pressure tested, and ensuring that integrity is maintained through an integrity management program that requires periodic assessments in these locations. Because hazardous liquid pipeline failure rates are low, and because the total pipeline mileage operated by operators with less than 500 miles of pipeline that could affect high consequence areas is small, the Final Rule has only a small effect on the likelihood of pipeline failure in these locations.

The Final Rule will result in more frequent integrity assessments of line segments that could affect high consequence areas than most operators are currently conducting (due to the 5-year interval required for periodic assessment). However, if the operator identifies and repairs significant problems discovered during the baseline inspection, and has in place solid risk controls to prevent corrosion and other threats, as they must, the benefits of assessing every 5 years versus the longer intervals operators more typically employ are not expected to be significant.

The Final Rule requires operators to conduct an integrated evaluation of all potential threats to pipeline integrity, and to consider and take preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause, like third-party damage, these evaluations should identify additional risk controls to address these threats. Some operators covered by the Final Rule already perform integrity evaluations or formal risk assessments that consider the environmental sensitivity and impacts on population. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. For these operators, it is expected that additional risk controls will be limited and customized to site-specific conditions that the operator may not have previously recognized.

Finally, an important, although less tangible, benefit of the Final Rule will be to establish requirements for operator integrity management programs that assure a more comprehensive and integrated evaluation of pipeline system integrity in high consequence areas. In effect, this will codify and bring an appropriate level of uniformity to the integrity management programs some operators are currently implementing. It will also require operators who have limited, or no, integrity management programs to raise their level of performance.

We expect this Final Rule to provide a more consistent, and overall, a higher level of protection for high consequence areas across the nation. Even though there is a benefit, we have concluded that it is not significant, and, therefore, have issued a finding of no significant impact.

Executive Order 13211

This rulemaking is not a "Significant energy action" under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects in 49 CFR Part 195

Carbon dioxide, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, we are amending 49 CFR part 195 as follows:

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

Subpart F—Operation and Maintenance

2. In § 195.452, paragraphs (a), (b), (d) heading, (d)(1), and (d)(2) are revised and paragraph (d) introductory text is added to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	1 year after the date the pipeline begins operation.

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	December 31, 2001.
Category 2	November 18, 2002.
Category 3	Date the pipeline begins operation.

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that—

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless—

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

* * * * *

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows:

(1) *Time periods.* Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004.
Category 2	February 17, 2009	August 16, 2005.
Category 3	Date the pipeline begins operation	Not applicable.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows:

Pipeline	Date
Category 1	January 1, 1996.
Category 2	December 18, 2006.

* * * * *

Issued in Washington, DC, on January 8, 2002.

Ellen G. Engleman,

Administrator.

[FR Doc. 02–858 Filed 1–15–02; 8:45 am]

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