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February 27, 1989

ORIGINAL
FILE COPY

Mr. Steve Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32301

Re: Docket No. 870098-EI

Dear Mr. Tribble:

Enclosed for filing are fifteen (15) copies of the Testimony and Exhibits of Florida Power & Light Company's witnesses, Messrs. R. R. Denis, E. L. Hoffman, G. G. Kuberek and T. S. LaGuardia in the above docket.

Respectfully submitted,

Matthew M. Childs, P. A.

MMC:bl

Enclosures

cc: All Parties of Record

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CERTIFICATE OF SERVICE
Docket No. 870098-EI

I HEREBY CERTIFY that a true and correct copy of the Testimony and Exhibits of Florida Power & Light Company's witnesses, Messrs. R. R. Denis, E. L. Hoffman, G. G. Kuberek and T. S. LaGuardia was furnished to the following persons by U.S. Mail on this 27th day of February, 1989:

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By: ______________________

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 870098-EI

FLORIDA POWER & LIGHT COMPANY

FEBRUARY 1989

IN RE: PETITION FOR APPROVAL OF AN
INCREASE IN THE ACCRUAL OF
NUCLEAR DECOMMISSIONING COSTS

TESTIMONY & EXHIBITS OF:

R. R. DENIS
E. L. HOFFMAN
G. G. KUBEREK
T. S. LAGUARDIA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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E. L. HOFFMAN

G. G. KUBEREK

T. S. LAGUARDIA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROBERTO R. DENIS

DOCKET NO. 870098-EI

February 27, 1989

Q. Please state your name and business address.

A. My name is Roberto R. Denis, and my business address is 9250 West Flagler Street, Miami, Florida.

Q. Who is your employer and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as Director of System Planning.

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

A. I received a Bachelor of Science degree, with Honors, in Electrical Engineering from Georgia Institute of Technology in 1972. In 1976, I completed an FPL sponsored course in the area of Nuclear Power. I have since attended numerous courses and seminars at Auburn

University, the General Electric Company, Ohio State University, and other industry associations.

I am a registered Professional Engineer in the State of Florida, and a member of the Florida Engineering Society and the Institute of Electrical and Electronic Engineers. I also represent FPL in the Interconnections Arrangements Committee of the Edison Electric Institute and at the System Planning Committee of the Florida Electric Power Coordinating Group.

Upon graduation in 1972, I was employed by FPL as a distribution engineer in FPL's Southeastern Division. In 1976, I joined the System Planning Department, where I was promoted to the position of Supervisor of Generation Planning in 1980. In 1982, FPL formed the Load Management and Customer Generation Department, at which time I was promoted to the position of Manager of that department. In 1985, I joined the Power Supply Department as the Manager of Contracts and Administration. In January of 1989, I assumed my present position as Director of System Planning.

In my present position, I am responsible for the evaluation of the Company's future need for power supply and transmission facilities and for the formulation of plans to satisfy such needs.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to discuss several factors which limit FPL's ability to make a definitive determination at this time regarding the ability to reuse any of the components or facilities at the Turkey Point and St. Lucie sites after nuclear decommissioning takes place.

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

A. Yes, I have. It consists of one document and it is attached to my testimony. This document shows the time frame in which nuclear decommissioning is anticipated.

Q. Are there any components now at the nuclear units which could be retained to generate electricity with another steam source after the removal of the current nuclear steam generation components?

A. The answer to this question is dependent on many factors which are unknown at this time and which will remain unknown during the foreseeable future. Components with potential for reuse after decommissioning would certainly be limited to the nuclear non-contaminated, components. These would primarily include portions of the turbine-generator power block, cooling system and electrical grid interconnecting facilities. The usability of these components however, will depend on the wear-and tear status at the time reuse is commenced.

Q. **Will the age of these facilities have an impact on their ability to be reused?**

A. Yes. It should be pointed out that, at the time of decommissioning, any remaining equipment will have been in service as long or longer than its expected life, assuming full-term operation of the units.

While it can be hypothesized that equipment will remain in usable condition, possibly subject to some refurbishment, the benefits of this "recycling" can only be evaluated in light of then existing environmental, economic and strategic concerns. Our ability to predict what these conditions may be in the long term is limited and makes such analyses highly speculative.

Q. **Could you please explain the problems with such long-term prediction?**

A. Yes. In order to put my discussion in perspective, Document No. 1, attached to my testimony, contains a table which attempts to specify the horizon for our predictions. The table shows that based on the recommended decommissioning approach, it will be 25 years from the present time before decommissioning is completed at the Turkey Point site and 39 years at the St. Lucie site. If we then were to add from five to ten years to those figures for permitting and construction of the facilities which would make use of such equipment, it is evident that equipment reuse is highly speculative given the uncertainties surrounding conditions at that time. The normal planning horizon at FPL for making decisions on capacity needs and technology selection is 20 years.

Q. **Does the time period between the start and completion of decommissioning contribute to the uncertainty?**

A. Yes. When the nuclear units are taken off-line and decommissioning commences, replacement capacity will likely be needed. Thus, whether additional capacity would be required after decommissioning is complete, several years later, is difficult to estimate.

It is my opinion that it is not reasonable or meaningful to attempt to predict the usability of any equipment at these two sites anywhere from 30 to nearly 50 years from now, because of the many uncertainties.

Q. **Are there uncertainties in addition to whether the non-contaminated equipment and facilities will be in good working order and reusable?**

A. Yes. As I mentioned before, if one wished to assume that certain equipment were usable, then it is necessary to consider whether it would be reasonable to reuse it. Since the time period we are dealing with is beyond that in which results from any economic planning exercise would be meaningful, other factors which affect the usefulness of any of the equipment or facilities would need to be evaluated.

Q. **Please discuss these factors.**

A. The first major hurdle, independent of the status of the equipment and facilities that must be overcome, is the permitting requirements under the Power Plant Siting Act. The permitting requirements under this Act fall in two general steps: 1) a Determination of Need, and 2) Site Certification/Environmental licensing.

Authority over the first of these is with this Commission and its objectives are to establish the need for the electrical facilities and to determine that the proposed facilities are *the most economical alternative available to the utility.* To satisfy the first requirement under the Siting Act, the type, size and timing of such facility must reasonably match the electrical demand of the Company's customers.

Whether reuse of the facilities is the most economical alternative to meet the electrical demand of FPL's customers is, however, more difficult to predict. It is not known whether repowering of these units is going to be economical at all 30 years from now. It is very difficult (if not impossible) to venture an answer to this question. As we look at historical technology innovations, it is likely that in 30 years or more we may be looking at a completely different technology for electric power generation. The answer to whether repowering will be an economically viable option for these units in that time frame is very unpredictable at this time. Therefore, even if there is equipment which could technically be reused, serious doubts exist that it may be the economical thing to do.

The second of the permitting steps poses even more formidable obstacles to being able to ascertain the ability to reuse equipment or facilities at the sites. One question is clear, whatever use is given to the sites for further power production must be compatible with the environment at that time or it will not be feasible to reuse the facilities. The location of both sites is such that the repowered facility would most likely be limited to a gaseous fuel which could be piped into the site. Solid fuels, such as coal, would require extensive transportation systems which neither site currently has. Oil most certainly will not be an economical fuel. Repowering with new nuclear reactors at those sites presents a greater political uncertainty than it is today. Therefore, the only foreseeable means of repowering at this time, from a fuel and environmental requirements standpoint, is the use of combustion turbines with heat recovery steam generators (CT/HRSG) to produce steam to turn the existing turbine generators.

Q. Have you performed any analyses to determine the feasibility of repowering these sites?

A. Yes, I have. However, it should be noted that repowering of a nuclear unit which has begun operation has not been done to date. Projects at Midland and Zimmer involve plants which had not been completed. My analysis shows that full repowering of the nuclear units at the Turkey Point site requires eleven 150 MW combustion turbine HRSG sets per unit for a total repowered capacity of 4,840 MW for the two units. At St. Lucie, the requirements are for thirteen 150 MW combustion turbine HRSG sets per unit for a total site capacity of 5,600 MW.

The basis for these requirements is that full repowering would be most attractive, and therefore pose the most economical alternative if the efficiency gains could be achieved for the entire capacity of the existing turbine generators.

Q. What do you mean by full repowering?

A. Full repowering involves total replacement of the steam supply system by combustion turbine HRSG sets. These CT/HRSG sets can provide the steam conditions necessary to drive an existing steam turbine generator at the site.

Q. Is partial repowering of the units an option?

A. The MW requirements detailed above assume that the entire steam volume necessary to drive the existing steam turbine generator would be provided by the CT/HRSG sets. Another possibility would be to provide some of the steam using a new or existing boiler and provide only partial requirements from the CT/HRSG sets. This is known as partial repowering. Use of the existing steam generator is not a viable option, since it is part of the "contaminated" system, and a new boiler as a practical matter, would probably not be economical since the partial repowering option results in reduced overall efficiencies compared to a full repowering. Partial repowering is, therefore, an unlikely option.

These analyses in turn raised some critical concerns with regards to land availability at the sites, fuel availability, water use and transmission line requirements.

Q. Could you please summarize these concerns for each site?

A. Yes, they are as follows:

Turkey Point

1) A total of 50 acres of land would be required to install the new facilities and accessories for a full repowering of both units. Configuration of the unit may be difficult within current site boundaries.

2) Up to 950,000,000 standard cubic feet per day of gas would be required to support the repowered units. There is currently no gas pipeline into this site and this volume represents over 100% of the currently planned Florida Gas Transmission capacity into the entire state of Florida.

3) An additional 2,000 gallons per minute of fresh water would be required to support the combustion turbines.

4) A minimum of an additional three 230kV circuits would have to be added into the plant site, preferably on a separate corridor, to export the total site generation, which would be greater than existing site capacity.

<u>St. Lucie</u>

1) A total of 60 acres of land would be required to install the new facilities and accessories for a full repowering. Configuration of the unit may be difficult within current site boundaries.

2) Up to 1,120,000,000 standard cubic feet per day of gas would be required to support the repowered units. There is currently no gas pipeline into this site and this volume represents 120% of the currently planned Florida Gas Transmission capacity into the entire state of Florida.

3) An additional 2,400 gallons per minute of fresh water would be required to support the combustion turbines.

4) A minimum of an additional four 230kV circuits would have to be added into the plant site, preferably on a separate corridor, to export the total site generation, which would be greater than existing site capacity.

Q. **What do you conclude from all this?**

A. I believe that even without concluding whether there will be equipment and facilities at the Turkey Point and St. Lucie sites that are capable of being reused, there are significant uncertainties regarding the physical requirements of repowering an existing turbine-generator power block which prevent a final determination of whether or not there is any practical or economic use of equipment currently at those sites.

Q. If the equipment has no practical or economic value, what use do you foresee for the land, cooling systems and transmission facilities currently at each site?

A. The future use of these presents a different question than ascertaining the use of existing power block equipment. Setting aside the reuse of existing power block equipment which itself creates questions because of the specific application, reuse of the sites themselves could be highly beneficial.

These sites are already developed with regards to cooling systems and transmission facilities. The sites are in near proximity to load centers providing for generation and load balance objectives which add to system reliability. Availability of new generation sites in the load areas surrounding these existing sites is questionable.

In the future, generating technology breakthroughs could very well make these sites usable. A clear advantage of all this would be that reuse of the sites in a manner which does not cause unacceptable environmental impact in either of the two locations could satisfy the needs of a growing Florida in an environmentally acceptable manner.

Q. Does this conclude your testimony?

A. Yes it does.

Florida Power & Light Company

Nuclear Decommissioning Table

Unit	Year of License Expiration	Year of Complete Decommission[1/]	Years of Lapsed Time[2/]
Turkey Pt. No. 3	2007	2013	24
Turkey Pt. No. 4	2007	2014	25
St. Lucie No. 1	2016	2028	39
St. Lucie No. 2	2023	2028	39

1/ Based on recommended decommissioning approach contained in testimony of FPL Witness Thomas S. LaGuardia.

2/ Time lapsed from present day. This would be the time lapsed to the first day any re-usable equipment would be available for other use from the present. It does not reflect the permitting and construction time request for any such reuse.

Docket No. 870098-EI
FPL Witness: Roberto R. Denis
Exhibit 1. Document No. 1
Page 1 of 1

E. L. HOFFMAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF EDGAR L. HOFFMAN

DOCKET NO. 870098-EI

FEBRUARY 27, 1989

Q. Please state your name and business address.

A. My name is Edgar L. Hoffman, Jr., 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 (Company) as Treasurer and Director of Finance.

Q. What is the purpose of your testimony?

A. To request consideration from the Commission for an increase in the Company's revenue requirements as they relate to the estimated costs associated with decommissioning the Company's four nuclear units at the St. Lucie and Turkey Point sites. The basis for this request is an updated engineering study performed by the independent consulting firm of TLG Engineering Inc. (TLG) which estimates an increase in the nuclear plant decommissioning costs upon which the current cost of service amounts are based. Additionally, my testimony is meant to present responses to issues related to the process of Nuclear Plant Decommissioning as it relates to those parts of the Studies filed with the Commission in 1988 for which I am the primary witness.

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

A. In January 1972, I graduated from the University of Wisconsin - Milwaukee with a Bachelor of Business Administration degree and received a Master of Business Administration degree in December 1974 from the same University.

In December 1971, I was employed by Wisconsin Electric Power Company, starting as a Financial Analyst and ultimately attained the position of Project Analyst. In 1978, I accepted the position with Florida Power & Light Company as a Senior Financial Analyst in the Finance Department. In 1980 I was promoted to Coordinator of Financial Planning and to Manager of Financial Analysis and Forecasts in December 1981. From December 1985 through May 1986 I was the Manager of Regulatory Accounting and Research. In June 1986 I was promoted to Director of Finance and Assistant Treasurer and to my current position as Treasurer and Director of Finance in January 1987.

Q. Are you sponsoring any schedules included in the Exhibits section of this filing?

A. No, I am not.

Q. **Before discussing the costs of nuclear decommissioning, what methodology is considered to be most appropriate by the Company for purposes of decommissioning its four nuclear units?**

A. Based on the Decommissioning Cost Studies prepared by TLG and the recommendation of Thomas S. LaGuardia of TLG, the Company's Decommissioning Steering Committee comprised of various Company executives, decided on the most appropriate decommissioning methodology for each of the Company's two nuclear sites. The Company chose to decommission its facilities in what may be considered a prompt, yet integrated manner. Factors considered in reaching a decision on the appropriate decommissioning methodology included cost, logistics, health, safety, security and the future regulatory environment.

The prompt (and integrated) decommissioning methodology is the least expensive of the conventional decommissioning alternatives (as defined in the Nuclear Regulatory Commission's (NRC) Nuclear Decommissioning Rule issued on June 27, 1988 and made effective July 27, 1988) available to the Company for both of its plants. As estimated by TLG, delayed decommissioning methods were anywhere from 11.3% to 23.7% more expensive for the St. Lucie Plant and from 11.2% to 30.4% more expensive for the Turkey Point Plant. Other important considerations dealt with eliminating potential uncertainties associated with a prolonged period of plant dormancy or entombment. Health and safety concerns related to a nuclear plant which sits idle for a prolonged period of time raise many unanswered questions. Concern for these health and safety uncertainties were expressed by the NRC in its Nuclear Decommissioning Rule. Absent any clear showing of why a nuclear plant should be decommissioned on a delayed basis, the NRC recommended prompt dismantlement. Lastly, the prompt decommissioning methodology limits the Company's exposure to potentially costly regulatory actions which could be imposed on utilities having plants that remain dormant or entombed for extended periods of time.

Each of the two sites - St. Lucie and Turkey Point - has two units. Consequently, it is necessary to integrate the decommissioning process so that, at each site decommissioning of both units is performed simultaneously.

The current license expiration date for each of the two units at the Turkey Point Plant is April 27, 2007. Because of identical license expiration dates, preparations for and the activities associated with decommissioning occur in an integrated fashion over very much the same period of time. The terminology used by TLG to describe this methodology in its Turkey Point Decommissioning Cost Study is Integrated Prompt Removal/Dismantling.

A similar approach is planned for the St. Lucie Plant. However, current license expiration dates for Unit Nos. 1 and 2 are March 1, 2016 and April 6, 2023 respectively. Given this seven year difference in license expiration dates and the Company's decision to integrate the decommissioning process, it will be necessary to prepare (through what is termed "mothballing") Unit No. 1 for a period of dormancy. This dormancy period will last until the license expiration date of Unit No. 2, at which time the decommissioning activities for both units will occur in an integrated fashion over the same period of time. The terminology used by TLG to describe this methodology in its St. Lucie Decommissioning Cost Study is Mothball/Prompt-Integrated Station Dismantling.

The integrated approach to decommissioning allows for a one time mobilization of personnel and equipment necessary to decommission the units at each of the two sites. The Company believes a one time mobilization effort will help to eliminate the potentially significant logistical considerations and costs necessary to organize resources at two different moments in time. Additionally, one time mobilization of resources allows for experience gained in the decommissioning of one unit to be more easily applied to the decommissioning processes at another unit.

Integrating the decommissioning process helps to eliminate concerns over having to secure one facility which is operating, from a unit which is being decommissioned. Congestion associated with decommissioning one unit could pose security problems at a site where another unit is still being operated. Important operational and safety considerations deal with the potential hazards associated with blasting activities necessary to complete the decommissioning process. Activities such as this which occur in close proximity to another unit which may still be operational, raise questions concerning the safety of continuing plant operations and its personnel. All of the previously mentioned points are especially true at the St. Lucie Plant, where license expiration dates are significantly different from one another.

Q. For the decommissioning methodology selected by the Company, what is the estimated appropriate cost in current (1988) dollars to decommission each of the nuclear units?

A. The cost estimates contained in the Decommissioning Cost Studies approved by the Company were expressed in 1987 dollars. Using the escalation rate methodology discussed in testimony which follows, the estimated 1987 costs were escalated by the Company and expressed in 1988 dollars. The escalation rate methodology used produced slightly different rates for each of the four nuclear units in 1988. Given below, for each of the four nuclear units are the 1988 escalation rates as derived and the estimated future costs of decommissioning in 1988 dollars.

Unit	1988 Escalation Rate	Estimated Future Costs in 1988 Dollars
St. Lucie No. 1	4.16%	$206,557,821
St. Lucie No. 2	4.14%	204,031,505
Turkey Point No. 3	4.21%	163,143,465
Turkey Point No. 4	4.17%	191,618,110

These costs were escalated to 1988 based on the Company's November 1987 Inflation Rate Forecast. An updated Inflation Rate Forecast is expected to be completed by the Company's Research, Economics and Forecasting Department in May 1989. The effect of this upcoming forecast on the above cost estimates is not known at this time but will be provided to the Commission when available.

Q. What methodology and escalation rate were used to convert the current estimated decommissioning cost to the future decommissioning estimated cost?

A. Summary explanations of the escalation rate methodology and detailed calculations of the rates used to escalate the 1987 decommissioning cost estimates provided by TLG are provided in each of the 1988 Decommissioning Cost Studies filed with the Commission. Following is a further explanation of the escalation rate methodology used by the Company.

The decommissioning process consists of several activities. These activities have been summarized in the Company's Decommissioning Cost Studies as: Decontamination, Removal, Packaging, Shipping, Burial, Staff and Other. The costs associated with each activity can be expected to increase at different rates throughout time. An escalation rate methodology which considers the potential for escalation rate differences between decommissioning activities was used.

The Company's methodology considers the current and projected costs of each of the above decommissioning activities separately for purposes of computing an overall, or average escalation rate. Each of the previously defined decommissioning activities is separated further into three component parts; labor, material and other. The proportionate cost (in 1987 dollars) for each of these three components was provided to the Company by TLG Engineering Inc. Using the decontamination activity for St. Lucie Unit No. 1 as an example, the proportion of labor, material and other costs as a percentage of total costs for the Decontamination activity was 65.5%, 34.5% and 0.0% respectively.

With each of the decommissioning activities separated into labor, material and other components, the inflation index, from the Company's official November 1987 Inflation Rate Forecast, which was believed to best characterize future escalation of each cost component was determined. The inflation index used for the labor component, depended on whether it was craft or staff labor. An Average Hourly Earnings Index for construction workers was used for craft labor. Staff labor was escalated using a similar Average Hourly Earnings Index for service workers. The Producer Price Index (for capital equipment) and the GNP Deflator were used to escalate material and the other cost components, respectively.

The escalated costs for each of the different decommissioning activities were determined for each year of the Study. Summing the escalated costs of all activities for a particular year and comparing this cost relative to the previous year's cost provided the annual escalation rate for the total decommissioning process from one year to the next. This process was repeated for each of the four nuclear units over the applicable analytical horizon.

An overall effective rate, equivalent to the year by year rates was determined for each unit and are shown below.

Unit	Overall Escalation Rate
St. Lucie Unit No. 1	5.5%
St. Lucie Unit No. 2	5.4%
Turkey Point Unit No. 3	5.4%
Turkey Point Unit No. 4	5.4%

Q. **Given this escalation rate methodology, what is the total estimated cost of decommissioning each unit in future dollars based upon the present operating license termination dates?**

A. The following future dollar cost estimates are based on the Company's November 1987 Inflation Rate Forecast. For each of the Company's four nuclear units the current license expiration date and the total estimated future cost of decommissioning is given below.

UNIT	LICENSE EXPIRATION	EST. FUTURE COST
St. Lucie No. 1	March 1, 2016	$1,370,729,178
St. Lucie No. 2	April 6, 2023	1,473,080,158
Turkey Point No. 3	April 27, 2007	503,344,063
Turkey Point No. 4	April 27, 2007	621,942,760

These estimated future costs apply only to the decommissioning methodology selected by the Company for each of its two plants; Mothball/Prompt-Integrated Station Dismantling for St. Lucie Unit Nos. 1 and 2, and Integrated Prompt

Removal/Dismantling for Turkey Point Unit Nos. 3 and 4.

The estimated future costs for St. Lucie Unit No. 2 include the obligations of the Orlando Utilities Commission and the Florida Municipal Power Agency which own 6.08951% and 8.806% of the Unit respectively.

Q. **As presently planned, in which years will the funds accumulated in the Nuclear Decommissioning Trust Fund be expended for each unit?**

A. The years in which funds are to be expended by the Company to meet the estimated costs of decommissioning each of the four nuclear units is given below.

Unit	Year(s) of Fund Expenditures
St. Lucie No. 1	2014 - 2028
St. Lucie No. 2	2021 - 2028
Turkey Point No. 3	2005 - 2013
Turkey Point No. 4	2005 - 2014

The timing of fund expenditures for each unit is based on the Engineering Cost Study performed for the Company by TLG Engineering, Inc. and the decommissioning methodology selected by the Company for each of its four units. The greater number of years over which funds will be expended for St. Lucie Unit No. 1 versus those of Unit No. 2 is attributable to the difference in the operating license expiration date for the units. Because the operating license of St. Lucie Unit No. 1 is currently expected to expire approximately seven years prior to that of St. Lucie Unit No. 2, fund expenditures are made for activities which enable Unit No. 1 to remain dormant until the license expiration of St. Lucie Unit No. 2. Upon License expiration of St. Lucie Unit No. 2, both Units will be decommissioned together on an integrated basis. Because there is no difference in license expiration dates for the Turkey Point Units, expenditures are made over approximately the same period of time.

Q. **What is the estimated future cost of decommissioning by unit in each year in which decommissioning funds will be expended?**

For each of the Company's four nuclear units the estimated future cost of decommissioning for each year in which funds are expended, is given below.

Turkey Point Plant

Integrated Prompt Removal/Dismantling

Year of Decommissioning	Estimated Future Cost Unit No. 3	Estimated Future Cost Unit No. 4
2005	$ 1,115,261	$ 611,541
2006	4,757,530	2,662,549
2007	30,421,764	22,037,228
2008	94,863,296	32,891,160
2009	126,463,249	110,230,751
2010	133,292,265	146,870,251
2011	67,745,350	154,801,245
2012	33,067,696	86,896,867
2013	11,617,652	51,398,161
2014		13,543,007
Totals	$503,344,063	$621,942,760

St. Lucie Plant

Mothball/Prompt - Integrated Dismantling

Year of	Estimated Future Cost	
Decommissioning	Unit No. 1	Unit No. 2
2014	$ 1,852,197	
2015	7,299,018	
2016	78,763,017	
2017	28,331,287	
2018	12,680,922	
2019	13,378,372	
2020	14,114,183	
2021	14,890,463	$ 1,276,476
2022	76,534,689	5,333,059
2023	262,488,312	61,780,306
2024	287,329,270	272,605,419
2025	303,132,380	353,445,292
2026	134,676,440	372,531,338
2027	124,327,707	232,741,082
2028	10,930,921	173,367,186
Totals	$1,370,729,178	$1,473,080,158

Q. **What are the annual accruals and revenue requirements in equal dollar amounts necessary to recover future decommissioning costs, net of tax, over the remaining life for each of the Company's nuclear power units?**

A. The following jurisdictional annual accruals and revenue requirements are needed to meet the estimated costs of decommissioning. These amounts are based on the Company's estimates of 1988 decommissioning costs and the November 1987 Inflation Rate Forecast which assumed an estimated decommissioning fund after-tax earnings rate of 5.6%.

Unit	Annual Accrual	Annual Revenue Requirements
St. Lucie No. 1	$ 9,923,209	$10,114,432
St. Lucie No. 2	8,092,801	8,248,752
Turkey Point No. 3	9,243,243	9,421,363
Turkey point No. 4	12,628,212	12,871,562
Total	$39,887,465	$40,656,109

The annual accruals and revenue requirements are assumed to be collected equally over the remaining operating life of each unit, beginning January 1, 1989. The annual accruals through the currently estimated remaining life of these units are amounts which will be needed to cover the currently estimated jurisdictional costs of decommissioning each of the four units. Because the Company is obligated to pay Regulatory Assessment Fees (0.125%) and Gross Receipts Tax (1.5%) along with a provision which must be made for

Uncollectible Accounts (0.2656%) on its total revenues, the above annual revenue requirements exceed the accruals. An increase in the Regulatory Assessment Fee from 0.0833% to 0.125% which became effective January 1, 1989 was approved by the Commission at an Agenda Conference in November, 1988. As a result, the above revenue requirements differ from those submitted in our 1988 Decommissioning Cost Studies.

The annual revenue requirements above, represent an increase of $21,471,337 over the Company's current revenue requirements of $19,184,772 as established in previous Commission Orders.

Q. **What method is currently used by the Company to fund for decommissioning costs?**

A. Prior to Internal Revenue Service (IRS) Code Section 468A which provided for the establishment of qualified funds, the Company made contributions to a non-qualified fund. Contributions to the non-qualified fund were to be used to meet the cost of decommissioning all of the Company's nuclear units. The IRS Code which now provides for the establishment of qualified funding arrangements enable the Company to make an annual election to make either qualified or non-qualified contributions to the fund(s). Unlike the non-qualified fund, contributions to a qualified fund must be used to meet the costs of decommissioning a specific nuclear unit. Mr. Kuberek, in his testimony, discusses the regulations which govern qualified funding elections by the Company.

Contributions to the qualified fund are made to an external trustee, State Street Bank & Trust Company (State Street), Boston, Massachusetts. State Street acts as a trustee for the qualified fund and has certain responsibilities to ensure that the qualified funds are in compliance with the requirements of Section 468A of the IRS Code and the terms and conditions of the Trust Agreement. In addition, State Street also provides custodial services to the Company as they relate to the qualified funds.

Contributions made to the non-qualified fund are also made to State Street, which also serves as Trustee for the non-qualified fund. State Street's responsibilities as Trustee for the non-qualified fund are not as broad as those required for the qualified fund. The Trustee has additional responsibility with respect to the qualified fund to ensure compliance with IRS Code Section 468A. The Company continues to control the selection of the investments for both the qualified and non-qualified funds.

As of December 31, 1988 the differences between actual fund balances and those which were projected in the Decommissioning Studies follow:

	Projected (000's)	Actual (000's)	Difference (000's)
Qualified	$ 69,609	$ 78,067	$ (8,458)
Non-Qualified	61,956	22,129	39,827
Combined	$131,565	$100,196	$ 31,369

The differences between actual and projected fund balances are attributable to:

$ 26.7 million	Federal income tax refund receivable for tax years 1984 through 1986.
1.4 million	projected earnings on the Federal income tax receivable.
1.7 million	current and future State income tax adjustments (or deductions).
0.1 million	projected earnings on 1988 State income tax adjustment.
1.4 million	market value versus book value.
$ 31.3 million	variance

For purposes of projecting decommissioning fund balances for year-end 1988 it was assumed in our Decommissioning Studies that the federal income tax refunds associated with Qualified Funding elections for years 1984 through 1986 had been received. To date, these refunds have not been received. Consequently, the above variance is largely due to timing differences.

The above State income tax adjustments are those attributable to making qualified funding elections for tax years 1984 through 1986. Because there is no actual State income tax refund associated with having made qualified funding elections for these years, the term "adjustment" is used to describe the fact that the Company takes a deduction on its State income taxes for purposes of realizing the amount attributable to qualified funding elections for years 1984 through 1986. A detailed explanation of the analytical treatment of the State income tax adjustments was provided in the 1988 Decommissioning Studies filed with the Commission. The assumed earnings rate on Federal and State income tax refunds/adjustments is 5.6%.

Q. What are the costs associated with the trustee services and portfolio management of the Company's nuclear decommissioning fund?

A. The fees payable to the trustee, State Street, are assessed on a sliding scale based on the market value of the securities being held and are paid by the Fund. The current fee schedule is as follows:

First $5 million	1/5th of 1%
Next $10 million	1/10th of 1%
Next $15 million	1/20th of 1%
Next $20 million	1/30th of 1%
Over $50 million	1/50th of 1%

In addition, nominal transaction and accounting fees are charged.

State Street was chosen as Trustee for the Fund because of their commitment to trust business, a high level of automation, technical sophistication and a competitive fee structure for services provided.

The management of the Fund's assets is presently performed by staff within the Finance Department. There are no plans to incur the additional cost of outside managers unless it could be demonstrated that an outside manager would provide an incremental return with an equivalent level of investment safety. The Company's pension consultants estimate that the Fund would incur an additional annual cost of between 25 to 50 basis points if outside managers were to be utilized.

Q. **What is the investment strategy for the Company's Nuclear Decommissioning Fund?**

A. The primary objective of the fund is to provide the capital necessary for the decommissioning of the Company's nuclear power plants at the end of their respective licensing periods. To accomplish this, the strategy is to maximize the earnings growth of the portfolio while maintaining a high degree of safety so as to minimize future customer contributions. Safety will be increased through the use of fixed income investments, with quality controls and diversification guidelines used to manage credit risk. The higher after-tax returns from investments in municipal securities further strengthens the portfolio in meeting its funding objective.

In January 1988, the Company's nuclear decommissioning fund was separated into two components, non-qualified and qualified. A qualified fund was established to realize the tax benefits offered in Section 468A of the IRS Code. Meeting the requirements of Section 468A requires the assets of the qualified fund to be invested in assets as defined in the "Black Lung Act", which are public debt securities of the United States, obligations of state or local governments or time or demand deposits. The monies remaining in the non-qualified fund are not subject to regulatory restriction.

The ability of a decommissioning fund to meet its future liabilities is based on the accuracy of cost estimates and the accompanying rate of inflation. Because inflation will play such an important role in meeting the future obligation of a decommissioning fund, the Company hopes to achieve a real return on the fund greater than the rate of inflation. To accomplish this, a decommissioning fund should pursue an investment strategy that is sensitive to change in the environment related to decommissioning costs, technology, regulation and financial market volatility. This means pursuing a course that diversifies market risk over time rather than matching all investment maturities with each plant's expected license expiration date. Because the Decommissioning Fund is a taxable entity, at the existing corporate tax rate of 34%, tax-exempt municipal securities provide the greatest economic benefit for both the qualified and non-qualified portfolios. Since establishing the reserve in 1983, the Company has pursued a strategy of using tax-advantaged fixed income instruments, namely, municipal bonds and preferred stock. Municipal bonds have consistently provided a higher after-tax benefit to the Fund than alternative taxable securities. During 1988 the average after-tax yield "pick-up" on new purchases of municipal bonds over U.S. Treasury Securities issued with comparable maturities was approximately 140 basis points.

Preferred stock has been an attractive investment from time to time because of the Dividends Received Deduction (DRD) to institutional investors. High quality sinking fund preferred stock has been used extensively in what is now labeled the non-qualified fund but has lost some of its appeal due to the reduction of the DRD to 70% from 85% and the general lack of supply of high quality issues.

Q. **What is the asset structure of the decommissioning portfolios and what has been the historical investment performance?**

A. On December 31, 1988 the asset mix of the decommissioning fund was as follows:

	Non-Qualified (000's)	Qualified (000's)	Combined (000's)
Cash & Equivalents	$ 274	$ 1,195	$ 1,469
Municipal Bonds	20,040	76,872	96,912
Preferred Stock	1,815	-0-	1,815
Total	$22,129	$78,067	$100,196

The historical investment performance as of December 31, 1988 is as follows:

	After-Tax Time Weighted Rates of Return			
	Past 1 Year	Past 2 Years	Past 3 Years	Since Inception
Combined Fund	3.6%	3.1%	5.6%	8.0%

Q. **How was the Company's 5.6% earning rate computed?**

A. Since earnings of the decommissioning funds are taxable, the funds receive the greatest benefit from tax free municipal bonds. An analysis of historical municipal bond yields was performed. Thirty-eight years of Moody's "Aa" 10 and 20 year municipal bond yields were examined and compared to the Consumer Price Index (CPI) for a like period. To smooth out the effects of market distortion, 30 year moving averages were calculated for both maturities. The 30 year moving average yield spread to CPI for the 10 year "Aa" municipal was calculated to be a negative 8 basis points. For the 20 year "Aa" municipal the spread was a positive 50 basis points. The average earnings rate was derived by weighting the average yield spreads to CPI of the 10 and 20 year "Aa" municipal bonds. By assuming a 50/50 weighting of the two spreads the following results were obtained:

Municipal Bond	Average 30 Year Spread Over/Under CPI	Assumed Weighting	Weighted Average 30 Year Spread Over/Under CPI
10 Year	-0.08%	50%	-0.04%
20 Year	0.50%	50%	+0.25%
			+0.21%

By adding the weighted average yield spread above to the CPI as forecasted by the Company, an after-tax earnings rate was derived.

Company's Long Term Average CPI Forecast	Weighted Average Spread Over CPI	Assumed Earnings Rate Forecast
5.4%	0.21%	5.61%

Since the assumed earnings rate is tied to the Company's forecast of the CPI this rate will be subject to change from time to time. As previously mentioned an updated Inflation Rate Forecast is expected to be completed in May 1989 which may impact the earnings rate forecast.

Q. **Why does the Company feel this rate is appropriate?**

A. Based on the taxability of the decommissioning fund, it was determined that the most meaningful proxy for future earnings growth would be to compare historical long term municipal bond yields against CPI. This long term look at historical municipal bond yields gives a good picture of the trend of bond yields during periods of both very low and high periods of inflation and the effects that the "oil shock" of the 1970's had on the market. This demonstrates that over long periods of time it is difficult to beat inflation.

Because of the limited and erratic supply of high grade preferred stock issues, it would be inappropriate to make an assumption that these higher yielding securities make up a significant part of the asset mix in the future and therefore, impact the Company's earnings rate assumption.

Total return measures include any unrealized appreciation or depreciation of a security which will vary with market fluctuations. This is particularly useful for securities which do not have a final maturity such as common stocks. Since the decommissioning fund is generally comprised of fixed income instruments which have a stated maturity and will be used to eventually fund a liability with a known payout date, it was determined that it will be the earnings cash flow and the compounding of those earnings that will provide the dollars required rather than price appreciation. For instance, assume a portfolio was to purchase a $1 million, 20 year bond at par, with a 5.6% coupon and that the reinvestment rate on the coupon payments is also 5.6%. Over the life of this bond the interest earned on interest represents over 40% of the total income. It is this income flow and accumulation of the reinvestment of that income that will finally determine the ability of the Fund to meet its obligation and therefore, was the determining factor in selecting this methodology. The Company's investment strategy has generally been one which focuses on long-term earnings accumulation, rather than one which attempts to capitalize on short-term price differentials between securities.

Q. **How often should contributions be made to the Company's Decommissioning Fund?**

A. The Company bills its customers for service provided on a monthly basis. A portion of the costs recovered in a billing cycle are considered costs associated with nuclear plant decommissioning. In that the costs are recovered by the Company on a monthly basis, monthly contributions to the fund are considered to be most appropriate. The current Decommissioning Studies assume that fund contributions and earnings are applied on a monthly basis.

Q. **Mr. Hoffman, does this conclude your testimony?**

A. Yes, it does.

G. G. KUBEREK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF

GARY G. KUBEREK

DOCKET NO. 870098-EI

FEBRUARY 27, 1989

Q. Please state your name and business address.

A. My name is Gary G. Kuberek 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 (the Company) as Assistant Comptroller Corporate Tax.

Q. Please describe your educational background and business experience.

A. I am a graduate of the University of Tennessee with a Bachelor of Science degree in Business Administration, with a major in accounting. In addition, I have completed the Executive Program in Business Administration at Columbia University. I was employed by the Company in

1972 and have worked in its Accounting Department since that time. I have held various technical and managerial positions with the Company, including Tax Analyst, Manager of Corporate Tax, Assistant Comptroller and Manager of Corporate Tax; Assistant Comptroller and Director of Corporate Taxes and Property Accounting and my present position, Assistant Comptroller Corporate Tax. I was Chairman of the Edison Electric Institute Taxation Committee for the fiscal year 1982-1983. Before joining the Company, I held various positions with the Internal Revenue Service.

Q. Will you please describe your duties as Assistant Comptroller Corporate Tax?

A. As Assistant Comptroller Corporate Tax, I am responsible for directing the Company-wide functions concerning taxes and providing tax policy guidelines to all levels of the organization. In addition, I am responsible for advising management of the effect of taxes on business decisions.

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

A. The purpose of my testimony in this proceeding is to explain the Company's accounting treatment for nuclear decommissioning costs included in the Company's cost of service and significant changes in regulations occurring subsequent to the Company's last decommissioning hearing.

Q. How are nuclear decommissioning costs accounted for in the Company's books and records?

A. In compliance with Order No. 10987, Docket No. 810100-EU, issued July 13, 1982, the Company recovers the estimated nuclear decommissioning costs over the remaining life of the nuclear unit. The nuclear decommissioning costs are recorded as a separate expense in sub-account 403, Depreciation Expense. The related decommissioning reserves are also segregated within the accumulated provision for depreciation. Revenues collected associated with nuclear decommissioning costs are deposited in the funds on a monthly basis.

Q. Are the parties owning an interest in the nuclear units of the Company required to provide for their proportionate share of the total decommissioning costs?

A. Yes. The participation agreements are associated with St. Lucie Unit No. 2 and are between the Company and Florida Municipal Power Agency (FMPA) and Orlando Utilities

Commission (OUC), respectively. These agreements state that the participants shall make funds "available for payment of decommissioning (and disposal) costs on the same basis and with the same priority as (those) provided by the Company". Excerpts from the FMPA and OUC agreements are included in my Document No. 1.

Q. Based upon the Company's previously approved study, what are the annual amounts included in cost of service for nuclear decommissioning?

A. The annual amounts previously approved by the Commission and required for nuclear decommissioning are as follows:

	Total Company	Jurisdictional
Turkey Point Unit No. 3	$ 5,504,080	$5,355,895
Turkey Point Unit No. 4	4,022,756	3,914,544
St. Lucie Unit No. 1	5,019,875	4,884,338
St. Lucie Unit No. 2	4,796,115	4,667,100

Q. Based on the Company's petition in this proceeding, what are the annual amounts required to be included in the Company's cost of service?

A. The annual amounts required for nuclear decommissioning as filed in the Company's petition are as follows:

	Total Company	Jurisdictional
Turkey Point Unit No. 3	$ 9,412,479	$ 9,243,243
Turkey Point Unit No. 4	12,859,425	12,628,212
St. Lucie Unit No. 1	10,104,895	9,923,209
St. Lucie Unit No. 2	8,240,974	8,092,801

Q. What is the projected date that each nuclear unit will no longer be included in rate base for ratemaking purposes?

A. For purposes of the present decommissioning filing, the Company projected that the nuclear units would be retired and removed from rate base for ratemaking purposes as follows:

Turkey Point Unit No. 3	April 27, 2007
Turkey Point Unit No. 4	April 27, 2007
St. Lucie Unit No. 1	March 1, 2016
St. Lucie Unit No. 2	April 6, 2023

Q. Have any laws been enacted or regulations been issued since the last decommissioning hearing which have a significant affect on nuclear decommissioning as discussed in your testimony?

A. Yes. Section 468A of the Internal Revenue Code was added by the Tax Reform Act of 1984 providing for an annual election to make a tax deductible contribution to a qualified nuclear decommissioning fund if certain conditions are met.

In 1986, the Treasury Department issued Temporary Regulations under Section 468A. The Temporary Regulations provided transition rules which allowed a tax deduction for cash payments to a qualified nuclear decommissioning fund for tax years 1984 through 1986. The final regulations were issued in March 1988.

On June 27, 1988, the Nuclear Regulatory Commission (NRC) issued a final rule amending its regulations, to be effective July 27, 1988, requiring that financial assurance be provided so funds will be available for decommissioning nuclear units. This assurance must be demonstrated by one of the following methods: 1) Prepayment prior to the start of operation; 2) External sinking fund, or 3) A surety method, insurance or other guarantee method. Under the prepayment or sinking fund methods, the NRC would require that funds for nuclear decommissioning be segregated from the licensee's other assets and outside the licensee's administrative control. In addition, the NRC rules require utilities with pressurized water reactor units to set aside certain minimum decommissioning funds based on megawatt thermal capacity. Under this rule, the Company would be required to provide a minimum of approximately $95 million per unit at Turkey Point and approximately $100 million per unit at St. Lucie (in 1986 dollars). These NRC estimates do not include costs to ship spent fuel and demolish non-radioactive structures, as the NRC does not consider these decommissioning activities. These amendments to the regulations effectively require a utility with an ownership interest in a nuclear unit to establish an external fund to provide for decommissioning of the nuclear unit.

In order to meet the conditions of Section 468A of the Internal Revenue Code and to comply with NRC requirements, the Company determined that the current arrangement, placing nuclear decommissioning funds with a trustee was required. This arrangement also complies with Order No. 10987 which states that "decommissioning cost of nuclear generating units shall be funded by use of a funded reserve".

Q. What is a qualified nuclear decommissioning fund?

A. A qualified nuclear decommissioning fund is a fund established to meet the requirements of Section 468A of the Internal Revenue Code.

Q. What is the purpose of establishing a qualified fund?

A. The purpose of establishing a qualified fund is to permit the Company the opportunity to make an election to take a tax deduction for cash payments to a nuclear decommissioning fund. In the absence of an election under Section 468A of the Internal Revenue Code, payments to a nuclear decommissioning fund are not tax deductible until economic performance, i.e. actual decommissioning, occurs.

Q. What are the major requirements under Section 468A of the Internal Revenue Code for obtaining a tax deduction for a payment to a nuclear decommissioning fund?

A. The major requirements which must be met under Section 468A of the Internal Revenue Code in order to obtain a tax deduction are:

1. The taxpayer must receive a ruling from the Internal Revenue Service approving the schedule of amounts (ruling amount) applicable to the nuclear decommissioning fund;

2. The payments to the fund must be included in cost of service for ratemaking purposes. However, such amount is limited to the ruling amount for tax deduction purposes;

3. The taxpayer must establish a nuclear decommissioning trust fund for each unit; and

4. The fund investments must be limited to those enumerated in Section 468A of the Internal Revenue Code.

In my Document 2, I have included selected pages from the executive summary of the Company's filing which explains in more detail the requirements, the tax consequences and advantages and disadvantages of a qualified fund.

Q. Why did the Company elect to make contributions to qualified funds for years 1984 through 1987?

A. In Order No. 17467, Docket No. 870273-EI, issued on April 27, 1987, the Commission required the Company to file requests with the Internal Revenue Service seeking ruling amounts under Section 468A. The Company filed its request for rulings on May 7, 1987 and was issued ruling amounts for the Turkey Point Units in December 1987 and the St. Lucie Units in January 1988. Upon receiving these ruling amounts, the Company had thirty days to make deposits to qualified funds for years 1984 through 1986 or lose the ability to make elections for such years. After giving consideration to the reduction in the corporate Federal income tax rate from 46% to 34%, effective July 1, 1987, the Company believed the advantages of the qualified fund outweighed the disadvantages for those years. The Company elected to make qualified contributions to nuclear decommissioning funds for tax years 1984 through 1986 and filed amended tax returns. Based on the previous analysis, the Company elected to make qualified contributions for 1987 in the original return as filed. The revenue requirements related to nuclear decommissioning determined in the Company's previous filing were premised upon a 46% Federal tax rate. With the lowering of the Federal tax rate to 34%, the Company incurred a projected deficiency in its funding. In fact, the annual revenue requirements requested under the petition as filed would have been higher had the Company not made these elections.

Q. Should the Company be required to elect qualified nuclear decommissioning contributions in the future?

A. No. While the required contribution must be funded each year, the Company decides whether to make contributions to either the qualified or nonqualified nuclear decommissioning fund based on the current facts and circumstances applicable to the Company. If the Commission were to require the Company to elect and make contributions to the qualified funds, it would take away the Company's ability to adapt to changes in circumstances in the future that might produce lower revenue requirements for our customers. By prescribing taxpayer elections, the Commission would impede the ability of the Company to avail itself of the most cost effective strategy and, therefore, I would strongly recommend against setting such a precedent.

Q. Does the Company believe its current filing will provide the funds necessary to decommission its nuclear units based on the current decommissioning study performed by TLG Engineering, Inc. and the cost escalation and inflation rates supported by the Company?

A. Yes. The Company believes that based on the current decommissioning study performed by TLG Engineering, Inc., and the cost escalation and inflation rates supported by the Company, the recovery of decommissioning costs set forth in its petition will be sufficient to decommission the nuclear units upon termination of their licenses.

Q. Should the dismantlement of nuclear non-contaminated plant components be included in the funding for nuclear decommissioning, or recovered separately through depreciation based on the lives and costs specifically related to those nuclear non-contaminated reusable components?

A. At this time, the dismantlement of the nuclear non-contaminated plant components is and should be included in the funding for nuclear decommissioning. If the nuclear non-contaminated portion of the unit is retired at the same time as the nuclear portion, there would be no significant difference in total costs since such costs have not been considered in current depreciation studies and removal of such costs from the decommissioning study would cause an offsetting deficiency in depreciation reserves. If, however, at a future time, the nuclear non-contaminated portion is determined to have a useful life beyond the nuclear portion, it may be preferable to recover the related removal costs as a component of depreciation to more closely associate these costs with each unit's period of generation.

Q. Should a decommissioning cost study be required from the Company addressing the exclusion of nuclear non-contaminated components and facilities which can be used for generation of power subsequent to decommissioning of the present nuclear components?

A. Currently, as discussed by Company witness, Mr. Denis, it does not appear that there is any basis to conclude that nuclear non-contaminated components will have any significant value upon decommissioning. If it can later be established that the nuclear non-contaminated components and facilities have a useful life beyond the nuclear facilities, a cost study should be required and the removal cost of the nuclear non-contaminated portion would be spread over the extended period the unit would provide generation. Since this is not presently the case, no change to the study filed in the Company's petition should be made.

Q. If a decommissioning cost study is required addressing the exclusion of nuclear non-contaminated components and facilities, in what time frame should it be required?

A. If the Commission decides it is in the ratepayers' best interest to separate the nuclear non-contaminated portion from the decommissioning study, I recommend that the proper time to incorporate this change would be in the Company's next decommissioning study.

Q. Does this conclude your testimony?

A. Yes, it does.

SECTION 18 - Decommissioning and Disposal

Company in its sole discretion shall have the authority to determine at any time when the Estimated Useful Life or Economic Life of St. Lucie Unit No. 2 has ended and thereupon to retire St. Lucie Unit No. 2. Company shall exercise said discretion in good faith. Thereupon, Company may take such action, on behalf of all Owners, as may be necessary to terminate operation and to place St. Lucie Unit No. 2 in a safe shutdown condition, and further may, in its sole discretion, decommission and dispose of and thereafter maintain St. Lucie Unit No. 2. Company shall have sole responsibility for, and is fully authorized to act on behalf of Participant with respect to termination of operation, decommissioning, disposal and subsequent maintenance of St. Lucie Unit No. 2 (including all related waste products and materials). Each Owner shall be responsible for its Ownership Percentage of all costs incurred in connection therewith (in accordance with Section 6), and shall be entitled to its Ownership Percentage of the salvage value of St. Lucie Unit No. 2. The provisions of this Section 18 are subject to the limited option provided in Section 20.

SECTION 19 - Provision for Decommissioning Costs

Beginning with Firm Operation, Company intends to provide for decommissioning and disposal costs through including in its depreciation rates and charges a negative salvage value applicable to St. Lucie Unit No. 2. Participant shall provide through its depreciation rates or through charges to its members or from other cash sources a provision for decommissioning and disposal costs based on Participant's Ownership Percentage no less at any time than that accumulated by Company in its depreciation rates or through other charges as reported to or ordered by the Federal Energy Regulatory Commission or its successor based on Company's Ownership Percentage. If Company, by its own decision or by order of any governmental authority, provides at any time a fund or other security for decommissioning and/or disposal of St. Lucie Unit No. 2, Participant shall contribute to such fund or other security in proportion to its Ownership Percentage or establish a separate fund or security in proportion to its Ownership Percentage of such decommissioning and/or disposal costs which fund or security shall be available for the payment of decommissioning and disposal costs with no less priority than the fund provided by Company.

DECOMMISSIONING
FUNDING ALTERNATIVES
QUALIFIED vs. NONQUALIFIED

Qualified Decommissioning Fund

Section 468A of the Internal Revenue Code (Code) provides for an annual election for contributions to a qualified fund. Listed below are the requirements imposed by the Code and Treasury Regulations which must be met to secure the tax deduction as well as the tax consequences of utilizing a qualified decommissioning fund:

Requirements:

1. In requesting and obtaining a schedule of ruling amounts:

   (a) The Internal Revenue Service (IRS) will not provide a schedule of ruling amounts until a public utility commission (1) has determined the amount of decommissioning costs to be included in the taxpayers' cost of service, and (2) has disclosed the after tax return and any other assumptions used in establishing or approving such amounts for taxable years beginning on or after January 1, 1987.

   (b) A request for an initial or revised schedule of ruling amounts must be filed with the IRS on or before the "deemed payment deadline date" of the first taxable year to which the schedule of ruling amounts will apply, i.e. March 15 of the succeeding taxable year for calendar year taxpayers.

DECOMMISSIONING
FUNDING ALTERNATIVES
QUALIFIED vs. NONQUALIFIED (Cont'd)

Requirements: (Cont'd)

2. The maximum amount which can be contributed to a qualified nuclear decommissioning fund cannot exceed the lesser of:

   (a) The amount of nuclear decommissioning costs included in the cost of service for a taxable year (to the extent such costs are directly or indirectly charged to customers of the taxpayer by reason of electric energy consumed during such taxable year or are otherwise required to be included in the taxpayer's income); or

   (b) The applicable ruling amount for that year. The taxpayer must secure a schedule of ruling amounts from the IRS that will generally be determined on the same basis as that used for regulatory purposes, except that the ruling amount may not exceed the amount necessary to fund that portion of nuclear decommissioning costs which bears the same ratio to the total nuclear decommissioning costs as the period for which the qualified fund is in effect bears to the estimated useful life of the nuclear unit.

3. The assets held by a qualified fund can be invested only in the following types of securities:

   (a) Public debt securities of the United Sates.

   (b) Tax-exempt obligations of a state or local government that are not in default as to principal or interest; or

   (c) Time or demand deposits in a bank or insured credit union located in the United States.

4. A separate qualified decommissioning fund must be established for each nuclear unit. The fund must be maintained at all times in the United States pursuant to an arrangement that qualifies as a trust under state law and must be established for the exclusive purpose of providing funds for decommissioning.

DECOMMISSIONING
FUNDING ALTERNATIVES
QUALIFIED vs. NONQUALIFIED (Cont'd)

Tax Consequences

5. The tax effects of making an election under Code Section 468A are:

   (a) Contributions to the fund are deductible as long as they are paid to the fund by the "deemed payment deadline date", i.e. March 15 of the succeeding tax year for calendar year taxpayers;

   (b) All distributions from the fund are included in the taxable income of the electing taxpayer with the exception of direct payments of administrative costs and other incidental expenses of the fund;

   (c) In substance the Code allows a deduction in the year of decommissioning only to the extent that decommissioning expenses exceed the amount distributed from the qualified fund for decommissioning expenses; and

   (d) Contrary to the tax law in general, the taxpayer receives no deduction for decommissioning expenses paid with earnings of the qualified fund.

6. The tax effects on the qualified decommissioning fund are:

   (a) Contributions are not taxable to the fund;

   (b) Earnings of the fund are taxable at the highest corporate rate in effect for the tax year in which the earnings accrue; and

   (c) Administrative expenses paid by the qualified decommissioning fund (other than an amount paid to the electing taxpayer) are deductible by the fund.

DECOMMISSIONING
FUNDING ALTERNATIVES
QUALIFIED vs. NONQUALIFIED (Cont'd)

Advantages of a Qualified Fund

The two primary benefits of a qualified decommissioning fund are the increased revenue requirement stability and increased security of the fund.

Stability

Increased stability is provided over the remaining life of the plant, including the period of decommissioning. This increased stability is a result of the levelized IRS method of funding whereby the effect of tax changes are levelized and no particular vintage of customer gets a windfall or detriment solely due to the timing of tax rate changes.

Security

Increased security of funds is provided, since contributions to a qualified decommissioning fund cannot be used for any purpose other than decommissioning and the fund is limited in the nature of investments permitted. This insures that the funds are used only for the reason they were intended and not used for any other purpose.

Disadvantages of a Qualified Fund

The primary disadvantage of a qualified fund is its inflexibility as evidenced by the inability to transfer over or underfunded amounts to other units, the limits on the maximum amount which can be funded and the restrictions on investment alternatives.

Transfers

The inability to transfer dollars between funds is the most serious problem since it removes the ability to make up a shortfall in one fund with an overage in another fund.

DECOMMISSIONING
FUNDING ALTERNATIVES
QUALIFIED vs. NONQUALIFIED (Cont'd)

Disadvantages of a Qualified Fund (Cont'd)

Contribution Limits

The limit on the amount which can be contributed to a qualified fund each year makes it impossible to realize the tax advantages of the qualified fund for all amounts collected. Any portion of the amounts collected attributable to nonqualified decommissioning costs cannot be contributed to a qualified fund. In addition, any amounts contributed to a qualified fund are limited to the amounts collected based on energy consumed during the taxable year in question.

Investment Alternative Limits

The limits on investment alternatives could be a disadvantage in times when other financial alternatives would be more attractive.

T. S. LAGUARDIA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF

THOMAS S. LAGUARDIA

DOCKET NO. 870098-EI

FEBRUARY 27, 1989

Q. Please state your name and address.

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752.

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

A. I am President of TLG Engineering, Inc (TLG Engineering).

Q. What are your responsibilities within that organization?

A. I am responsible for the technical and business management of the engineering consulting services in the areas of decontamination, decommissioning, waste management and general engineering for nuclear and fossil fueled generating stations.

Q. Please outline your educational qualifications and experience.

A. I completed my BSME at Polytechnic Institute of Brooklyn in 1962 and my MSME at the University of Connecticut in 1968. I am a registered professional engineer in Connecticut (No. 10393) and New York (No. 059389). I founded TLG Engineering in April, 1982. I was employed by Nuclear Energy Services in Danbury, Connecticut from 1973 until I founded TLG Engineering. Prior employment was with Gulf Nuclear Fuels Corporation (formerly United Nuclear Corporation (UNC)) and Combustion Engineering.

Q. What is your experience relating to decommissioning?

A. My decommissioning experience began as site representative for UNC during the BONUS reactor decommissioning in 1969 and 1970. BONUS was a 17 MWe demonstration power reactor and the largest reactor decommissioned by entombment up to that time. The program involved extensive chemical decontamination of radioactive systems, selective piping and component removal, and entombment of the reactor vessel within a massive concrete barrier. The entombment has a design life of 125 years. My role as site representative was to act as a technical liaison and provide project engineering and schedule management assistance during system decontamination, component removal, vessel entombment and facility closeout.

Following the BONUS program, I was lead engineer for UNC during the Elk River Reactor decommissioning between 1970 - 1974. Elk River was a 20 MWe demonstration power reactor that was decommissioned by complete dismantlement. The program involved segmentation of the reactor vessel and internals using remotely operated cutting torches, as well as the packaging, shipping and controlled burial of the segments.

Similarly, radioactive piping and components were removed, packaged, shipped and buried. Radioactive concrete was demolished by controlled blasting, and nonradioactive concrete demolished by wrecking ball to completely dismantle the facility. Initially, my role for UNC was consulting engineer and later lead engineer for UNC technical support for on-site activities.

I was Project Engineer for the detailed engineering and planning of the Shippingport Station Decommissioning Project from 1979 - 1982. Shippingport was a 72 MWe light water breeder reactor. The facility is now almost completely dismantled, and TLG, with its joint venture partner Cleveland Wrecking Company, dismantled all of the piping and components and removing contaminated concrete. My role for TLG/Cleveland was Project Director, and I selected and managed an on-site project management team to hire and supervise work crews to accomplish the dismantling. Our work is complete and was performed on schedule and within budget.

I also assisted Atomic Energy of Canada, Ltd. in the detailed engineering and planning of the 238 MWe Gentilly Unit 1 reactor. My role was to provide overall decommissioning consulting services and detailed cost estimation of alternatives.

Q. What studies or reports have you prepared or co-authored on decommissioning cost estimating and technology?

A. While at Nuclear Energy Services, I was principal investigator for the Atomic Industrial Forum decommissioning study entitled "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives" (AIF/NESP-009). This study evaluated the costs, schedule and environmental impacts of decommissioning 1100 MWe reactors (Pressurized Water Reactors [PWRs], Boiling Water Reactors [BWRs], and High Temperature Gas Reactors [HTGRs]).

I also co-authored the "Decommissioning Handbook" for the U.S. Department of Energy (DOE). The Handbook reported the state of the art in decommissioning technology (as of 1980), including decontamination, piping and component removal, vessel segmentation, concrete demolition, cost estimating and environmental impacts.

At TLG Engineering, I co-authored "Guidelines for Producing Commercial Nuclear Power .lant Decommissioning Cost Estimates" (AIF/NESP-036) for the Atomic Industrial Forum, National Environmental Studies Project. The Guidelines identify the elements of costs to be included in the estimation of decommissioning activities for each of the principal decommissioning alternatives. Specific guidance in cost estimating methodology and reference cost data is provided in this study. The major objective of this study is to provide a basis for consistent cost estimating methodology.

TLG Engineering also prepared a study entitled, "Identification and Evaluation of Facilitation Techniques for Decommissioning Light Water Power Reactors" (NUREG/CR-3587) for the Nuclear Regulatory Commission (NRC). The study evaluated the costs and benefits of techniques to reduce occupational exposure and waste volume from decommissioning. TLG Engineering has prepared site-specific decommissioning studies for most of the nuclear units in the United States and 21 fossil-fueled power plants. In addition, TLG prepared the Decommissioning Plan and Environmental Report (ER) for Dresden Unit 1, and the ER for Indian Point Unit 1.

Q. What is the purpose of your testimony?

A. I am presenting the results of the 1987 decommissioning cost studies prepared under my direction and supervision for the St. Lucie Nuclear Unit Nos. 1 & 2 and the Turkey Point Unit Nos. 3 & 4. This study was commissioned by the Florida Power & Light Company (Company) as owner and operator of the stations. My testimony includes the decommissioning alternatives evaluated, cost and schedule estimates, and a discussion of decommissioning feasibility.

Q. What is the purpose of the decommissioning studies?

A. The purpose was to estimate the cost of decommissioning the two nuclear sites so that the contributions required to establish a decommissioning fund can be determined. The study is not a detailed decommissioning engineering plan, and therefore, does not commit the participants to a specific course of action for the station following ultimate plant shutdown.

Q. What are the costs of each decommissioning alternative?

A. The costs for each decommissioning alternative are shown in my Documents 1 and 2, for the St. Lucie nuclear station and the Turkey Point nuclear station, respectively. Each decommissioning scenario involved one or a combination of the three accepted decommissioning alternatives; DECON, ENTOMB and SAFSTOR. The costs associated with each of the alternatives are reported in constant 1987 dollars and include 25% contingency. The cost estimates do not include future inflation or consider the cost of money over the time period involved.

Q. What decommissioning scenarios were considered for St. Lucie station?

A. Four scenarios were reviewed for the St. Lucie Station. The first scenario assumed that the two units on the site were decommissioned as they are taken out of service with no impact or interface with the adjacent unit. This is possible due to the differential in the issuance of the operating licenses 1976 for Unit 1 and 1983 for Unit 2. The second scenario integrates the decommissioning by mothballing Unit No. 1 upon shutdown until such time that Unit No. 2 nears the cessation of operations. At this time a delayed dismantling program is initiated for Unit No. 1 such that the Unit No. 2 prompt decommissioning is properly sequenced. The final two scenarios involve standard mothball and entombment programs for the two units as they are retired. However, the dormancy durations for Unit No. 2 have been shortened to approximately 24 years such that the delayed dismantling program of the second unit can be integrated with that of Unit 1.

Q. What are the costs of each decommissioning alternative considered at Turkey Point?

A. My Document No. 2 provides the costs for each decommissioning alternative for the Turkey Point nuclear units. The operating licenses currently expire on the same date. Consequently, only three scenarios were costed. All three considered the integration of the decommissioning programs for the site as a whole. As a result the scheduling of the prompt removal program for Unit 4 and the dormancy periods for the delayed dismantling programs were adjusted such that decommissioning of the two units was integrated.

Q. What is the basis for the decommissioning studies?

A. The studies were developed using the detailed engineering drawings, together with plant description and inventory documents provided by the Company as owner and operator. These drawings and documents were used to identify the general arrangement of the facility and to determine estimates of building concrete volumes, steel quantities, numbers and size of components and degree of site restoration required.

I personally made a site inspection of the plant, including access to the facility to determine movement of heavy equipment (cranes, forklifts, front-end loaders) close to the structures for demolition and removal work.
Decommissioning is a labor-intensive program. Representative labor rates for each geographical region and each craft or salaried work group are essential for development of a meaningful site-specific decommissioning cost estimate. Accordingly, the Company provided typical craft labor rates and utility salary data.

Rates for shipping radioactive wastes for burial were obtained from tariffs published by Tri-State Motor Transit. Tri-State Motor Transit is a reputable carrier with many years of experience in handling radioactive fuel and low level radioactive wastes. Transportation costs are an important element of decommissioning costs and recent rates must be used for accurate site-specific cost estimates. For this study, we assumed all low-level radioactive waste would be shipped to a hypothetical regional burial ground within 500 miles of the St. Lucie site and 600 miles from Turkey Point. For cost estimating purposes, the burial costs for radioactive materials were developed using the rate schedule of an existing disposal facility, i.e. the Barnwell Low-Level Radioactive Waste Management Facility.

Q. Are there any federal regulations governing nuclear decommissioning?

A. Yes. The United States NRC has regulations dealing with the issue of decommissioning. These regulations are identified in Title 10 of the US Code of Federal Regulations (CFR) Parts 20, 30, 40, 50, 51, 70, and 72, and specific guidance for their implementation is provided in NRC Regulatory Guide 1.86 (June, 1974).

The NRC published the Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" in the Federal Register of Monday, June 27, 1988 to establish technical and financial criteria for decommissioning licensed facilities. As discussed later the new NRC Rule recognizes the advantages of a site-specific cost estimate for decommissioning funding, and recommends that decommissioning be accomplished in the shortest practical time following cessation of operations. The decommissioning cost estimates prepared for the St. Lucie and Turkey Point nuclear units fully satisfy each issue of this new regulation.

Q. What methodology was used to prepare the cost estimate in your studies?

A. The methodology used to develop the cost estimate followed the basic approach presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates", and the U.S. DOE "Decommissioning Handbook".

These references use a unit cost factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit cost factors for activities such as concrete removal ($/cu yd), steel removal ($/ton), and cutting costs ($/in.) were developed from the labor and material information provided by the Company. With the item quantity (cu yds, tons, inches, etc.) developed from plant drawings and inventory documents, the activity-dependent costs for decontamination, removal, packaging, shipping and burial were estimated. The activity duration critical path derived from such key activities, e.g. the disposition of the Nuclear Steam Supply System (NSSS), was used to determine the total decommissioning program schedule.

The program schedule is used to determine the period-dependent costs such as program management, administration, field engineering, equipment rental, quality assurance and security.

The salary and hourly rates are typical for personnel associated with period-dependent costs. The costs for conventional demolition of non-radioactive structures, materials, backfill, landscaping and equipment rental were obtained from conventional demolition references such as R. S. Means, "Building Construction Cost Data 1987".

In addition, collateral costs were included for heavy equipment rental or purchase, sarety equipment and supplies, energy costs, permits, taxes, and insurance.

The activity-dependent, period-dependent, and collateral costs were added to develop the total decommissioning costs. A 25% contingency was added to allow for the effect of unpredictable program problems on costs. Such a contingency is appropriate for a project of this size and type, as will be discussed later in this testimony.

One of the primary objectives of every decommissioning program is to protect public health and safety. The cost estimates for the St. Lucie and Turkey Point decommissioning activities include the necessary planning, engineering and implementation to provide this protection to the public.

Q. Have you considered the removal of spent fuel in your cost estimate?

A. No. It is important to note that although decommissioning of a site cannot be complete without the removal of all spent fuel and source material, the disposition of high-level waste is outside the scope of decommissioning. In accordance with the Nuclear Waste Policy Act of 1982 (Public Law 94-425), the DOE is required by law to enter into contracts with owners and/or generators of spent fuel, with the DOE responsible for final dispositions of spent fuel as high-level nuclear waste. To cover the cost of spent fuel disposition, the DOE assesses the facility operator 1 mill/kWh on net electrical generation. Therefore, the cost and disposal of spent fuel is accounted for separately and is specifically excluded from the decommissioning estimates.

All radioactive wastes generated during the decommissioning process are low-level radioactive wastes and will be transported to a federal or state licensed commercial low-level waste facility for ultimate disposal, as required by the appropriate regulations in effect at the time of decommissioning.

Q. What decommissioning alternatives were considered in preparing the cost estimates?

A. Estimates were prepared addressing the three basic decommissioning alternatives: (1) DECON (prompt removal/dismantling), (2) ENTOMB (safe storage entombment with delayed dismantling), and (3) SAFSTOR (safe storage mothballing with delayed dismantling). These alternatives may be briefly summarized as follows:

1) The DECON (prompt removal/dismantling) alternative consists of removing from the site the spent fuel assemblies discharged from the reactor and stored on site. Note that the cost associated with the disposition of fuel and source material is not included in this estimate. All radioactive wastes from plant operation would be packaged and shipped for controlled burial. The operating license would be converted to a possession-only license for the decommissioning operations. A possession-only license permits the owner to possess the radioactive material under reduced Technical Specification requirements, but prohibits operation of the reactor. The radioactive fission and corrosion products and all other radioactive materials having activities above accepted unrestricted levels would be removed, packaged and shipped for disposal. The site may then be released following NRC approval, for unrestricted use with no requirement for a license. The remainder of

the reactor facility could then be dismantled to make the site available for alternative use.

2) The ENTOMB (safe storage entombment) alternative consists of removing from the site all fuel and radioactive wastes from operations. The cost for disposal of fuel is not included in this decommissioning estimate as discussed in the previous alternative. A possession-only license would be obtained, selected radioactive material would be removed from the site, and all remaining radioactivity would be sealed within an entombment barrier. A remotely monitored security intrusion system would be put in operation, and periodic surveillance, inspections and continuing facility repairs and maintenance would be provided to ensure entombment integrity. Following a dormancy period, the plant would be decontaminated/dismantled as described in the DECON alternative.

3) SAFSTOR (Safe storage mothballing) consists of the same basic site deactivation activities as carried out in the entombment method except that radioactive components are neither shipped off-site nor centrally stored within an entombment barrier. Piping and components would be drained and dried, and left on site. An adequate

security force would remain on the site, thereby increasing the annual maintenance costs when compared with entombment. As with the entombment, the decontamination/dismantling activities are delayed to a later date.

Q. Does the NRC have a requirement as to completion of decommissioning?

A. Yes. The NRC has stated that for an electric utility licensee, an alternative is acceptable if it provides for completion of decommissioning within 60 years. Consideration will be given to an alternative which provides for completion of decommissioning beyond 60 years only when necessary to protect the public health and safety.

Q. What is your recommended scenario for each of the Company's nuclear sites?

A. I recommend that the Company, for planning purposes, have their funding determined based upon the following decommissioning scenarios: placing St. Lucie Unit 1 into SAFSTOR for a period of approximately 5 years at which time decommissioning activities could commence in conjunction with Unit 2; decommissioning the two Turkey Point nuclear units upon final shutdown, i.e. an integrated DECON scenario. These alternatives provide the most reasonable means for terminating the license for the site in the shortest possible time, and consequently relieves the Company of its regulatory and liability obligations at the site. Furthermore, this scenario avoids the long-term costs and commitments associated with the maintenance, surveillance and security requirements of the conventional delayed dismantling alternatives, SAFSTOR and ENTOMB.

The recommended alternatives also allow use of the plant's knowledgeable current operating staff, a valuable asset to a well managed, efficient decommissioning program. All equipment needed to support decommissioning operations such as cranes, ventilation systems and radwaste processing equipment would be fully operational. In addition, the site would be available for alternative uses in the near term.

Q. When does actual decommissioning of a nuclear facility begin?

A. Approximately two years prior to final shutdown, engineering and planning would begin on the preparation of the Decommissioning Engineering Plan and Environmental Assessment. The Plan describes the status of the facility at shutdown, work to be accomplished, safety analyses associated with each of the major activities, general procedures and sequence to be followed, and final site condition upon completion of all work. Similarly, the environmental assessment would evaluate environmental effects (radiation exposure) to workers and the public, and waste generation effects on the site and environment. These documents would be submitted to the NRC and other regulatory agencies for review and approval, and authorization to proceed.

Q. What are the various stages of decommissioning?

A. Period 1 - Site Preparations - would begin upon shutdown of the facility, and would involve site preparations to initiate decommissioning. The operating license may be converted to a possession-only license which permits decommissioning activities to be performed, while reducing unnecessary Technical Specifications requirements associated with normal plant operations. All spent fuel would be removed from the reactor vessel and loaded into casks for transport to storage facilities on-site so as not to impact the decommissioning process. As noted earlier, fuel removal activities, packaging, shipping and disposal are not considered part of decommissioning and no costs are included in the decommissioning estimate for this work nor is any impact on decommissioning from the presence of such material on-site considered or costed in the estimates. All fluids and wastes remaining from plant operations would be removed from the site and all systems nonessential to decommissioning would be isolated and drained. This work is expected to require approximately 12 months to accomplish.

The following activities are performed both in the DECON alternative and in the delayed dismantling part of the SAFSTOR alternative. Consequently, both Period identifiers are shown, e.g. Period 2/4 indicated that the activities are applicable to both Period 2 of DECON (the first numerical identifier) and Period 4 of SAFSTOR. Period 2 of SAFSTOR is the dormancy phase, with Period 3 addressing site reactivation.

Period 2/4 - Decommissioning Operations - would begin upon receipt of the dismantling order from the NRC. This phase of the work involves the removal of radioactivity from the site and termination of the license. The activities include selective decontamination of contaminated systems, e.g. using aggressive chemical solvents to dissolve corrosion films holding radionuclides, thereby reducing radiation levels.

While effective, the decontamination processes are not expected to reduce residual radioactivity to the levels necessary to release the material as clean scrap. Therefore, all contaminated components will have to be removed for controlled burial. However, decontamination will reduce personnel exposure and permit workers to operate in the immediate vicinity of most components, cutting and removing them for controlled disposition at a low-level waste burial facility.

All piping to and from major components such as the steam generators will be cut and removed. The steam generators and other major components will be removed intact and sealed so that they may be shipped as their own containers for disposal. Smaller components will be loaded into containers and shipped for burial.

The reactor vessel and its internals will be segmented into sections and remotely loaded into steel liners for transport to the burial facility in heavily shielded shipping casks. The reactor vessel and internals have sufficiently high radiation levels to require all cutting to be done underwater (to shield the workers), or behind heavy shields, using cutting torches operated by remote control.

Concrete immediately surrounding the reactor vessel is expected to be radioactive (activated) and will be removed by controlled blasting. This blasting process is well developed and safe and is the most effective way to remove the heavily-reinforced concrete from the structure. Sections of interior floors within areas of the containment and other buildings in the power block are expected to be surface contaminated from exposure to contaminated air/water as a result of plant operations. This contamination will be removed by scarification (surface removal) so the remaining surface will be clean and not require costly controlled burial. All contaminated process equipment, pipe hangars, supports and electrical components will be removed and disposed of by controlled burial. An extensive radiation survey will be performed to ensure all radioactivity above the levels specified has been removed from the site. The facility may then be released for unrestricted access. Once verified the NRC can then terminate the license for the site. This period is expected to require approximately three years to accomplish all activities.

Period 3/5 - Dismantling of Remaining Structures - would involve the demolition of all remaining structures, typically to a depth of three feet below grade. Clean rubble would be used on-site for fill and additional soil would be used to cover each subgrade structure. The site would be graded. This period is expected to require approximately two years to accomplish all activities.

Q. What is the cost estimate validity and how is it applicable in the future?

A. The cost estimates prepared for the St. Lucie and Turkey Point nuclear units are based on current state-of-art technology and on current federal regulations. No provision is made to include future costs (improvements in technology, major regulatory changes, inflation factors, etc.) to ensure there will be no double accounting for such factors when projecting costs to the expected date of decommissioning. It is my recommendation that the Company thoroughly review this estimate periodically and revise it, if necessary, to account for cost increases or decreases as influenced by future technology and regulations. It is my understanding that the Company intends to follow my recommendation.

Q. Is there a contingency factor in your studies and, if so, how much is it?

A. The contingency factor is 25%.

Q. What is the purpose of the contingency?

A. The purpose of the contingency is to allow for the costs of high probability program problems where the occurrence, duration, and severity cannot be accurately predicted. The American Association of Cost Engineers (AACE) (in their cost Engineers Notebook) defines contingency as follows:

> Contingency - specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur.

Therefore, the objective of the contingency is to account for the costs of high probability program problems where the occurrence, duration, and severity cannot be accurately predicted and have not been included in the basic estimate. Past decommissioning experience has shown that these problems are likely to occur and may have a cumulative impact.

A more extensive discussion of contingency is included in the AIF/NESP-036 Guidelines Study (Chapter 13) referred to earlier. In that study, we examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, shipping and burial) with respect to reasons for contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from our actual decommissioning experience. The overall contingency, when applied to the appropriate components of a standard cost estimate, results in an average of approximately 25%. Therefore, we recommend that a 25% contingency be added to the total estimated costs for financial planning purposes.

Q. Is there any other support for a contingency factor?

A. Yes. Independent of our preparation of the AIF/NESP-036 study and its predecessor report, AIF/NESP-009, Battelle Pacific Northwest Labs prepared independent decommissioning cost estimates for the NRC for an 1175 MWe PWR (NUREG CR-0130) and an 1155 MWe BWR (NUREG CR-0672). Battelle concurred with the 25% contingency allowance.

Furthermore, the Federal Energy Regulatory Commission (FERC) adopted 25% contingency as reasonable, following the ruling of Judge Liebman in the Middle South Energy/Grand Gulf Case (Docket ER82-616), decision issued February 3, 1984. Numerous state public utility commissions have adopted 25% contingency, as evidenced by an American Gas Association Edison Electric Institute Depreciation Committee Survey which showed that at least 21 of 32 utility survey respondents had included 25% contingency in their estimates. Of the 15 utilities who filed rate cases, 11 had approval to use 25% contingency for their plant decommissioning studies.

Q. What is the basis of the feasibility of the decommissioning premise?

A. There is extensive experience in the United States and in other countries for the complete dismantling of nuclear plants. This experience includes the chemical decontamination, component removal, packaging, shipping and burial, and building demolition. This directly related experience summarized herein is evidence that the Company's nuclear units can be completely dismantled.

Between 1960 and 1979, 68 licensed nuclear reactors had been or were in the process of being decommissioned in the United States. Of these, five were nuclear power plants, four were demonstration nuclear power plants, six were licensed test reactors, 28 were research reactors. The remaining 25 were critical reactors and/or critical facilities decommissioned or scheduled to be decommissioned. They have been or will be totally dismantled, with their licenses terminated. Many other reactor facilities in the United States, Canada and Europe have been successfully decommissioned using demonstrated techniques. France decommissioned 13 reactors, Germany (FR) 6, Italy 8, Japan 7, Switzerland 2, United

Kingdom 5, and Canada 2.

The feasibility of decommissioning in the United States is well documented in the successful dismantling of Shippingport Atomic Power Station, Elk River Reactor, Walter Reed Army Research Reactor, Ames Laboratory Reactor and Sodium Reactor Experiment (SRE) Facilities. Internationally, the decommissioning programs underway in England (Windscale Reactor), Germany, [FR) (Gundremmingen), and Japan (Japan Power Demonstration Reactor) are further evidence of demonstrated technology. The basic activities of cutting pipe, segmenting vessels, demolishing reinforced concrete and decontaminating contaminated systems and structures are independent of the size of the structure or megawatt rating of the plant on a unit cost factor basis ($/cut, $/cu yd, etc.). A contaminated 12-inch diameter pipe in a 3000 MWt plant takes as long to cut as it does in a 58 MWt plant, although the number of cuts will be greater in the larger plant. The technology of such cutting is well established.

The major activities include removal and burial of contaminated piping and components using conventional power hack saws, oxyacetylene or plasma arc torches within a contamination control tent. Removal of the reactor vessel and internals can be accomplished using an arc-gouging fuel gas torch or an arc saw which is currently capable of cutting through carbon and stainless steel up to 12 inches thick (current vessels are less than 10 inches thick). The remote manipulator technology required to cut the reactor vessel and internals was developed by Oak Ridge National Laboratory for the Elk River Reactor dismantling. This technology uses the plasma arc torch for cutting. This same tool was used in the SRE vessel cutting activity.

Many of the tools and techniques used in decommissioning have been used in operating plants for maintenance and equipment replacement programs. This technology is, therefore, not unique and provides further evidence of the feasibility of decommissioning.

In 1979, Virginia Electric and Power Company removed and replaced the contaminated 823 MWe steam generators in its Surry plants. The contaminated steam generators (measuring 65 feet high by 170 inches outside diameter with 3.5 inch thick walls) each weighed 340 tons. The reactor coolant system stainless steel piping (34 inch inside diameter), steam piping (30 inch diameter) and feedwater piping (14 inch diameter) were cut with a plasma arc torch to isolate the steam generator from the primary and secondary systems.

The steam generator shell was circumferentially cut at the transition cone with the plasma arc torch. The two lower shell sections were removed through the existing equipment hatch for disposal. In 1981, a similar steam generator removal program was initiated and successfully performed by the Company at its Turkey Point Station.

Controlled blasting concrete demolition methods are well developed. They have been used in the mining industry, and were successfully demonstrated in the demolition of the Elk River Reactor. Heavily reinforced eight feet thick concrete sections of the biological shield were safely removed with explosives, without damaging or interfering with the operation of adjacent operating power generating units. The successful application of these decommissioning techniques in both small and large nuclear power plants demonstrates assurance of decommissioning feasibility. Both the technology and the methodology for efficient decommissioning are available and fully tested.

Q. What does the NRC's rule on decommissioning "General Requirements for Decommissioning Nuclear Facilities" as published in the Federal Register on Monday, June 27, 1988 require?

A. The Rule, as published, requires licensees to assure the availability of funds by submitting a decommissioning funding plan. The Rule identifies the acceptable decommissioning alternatives I described earlier: DECON (prompt removal/dismantling), SAFSTOR (mothballing), and under special circumstances ENTOMB (entombment). Delayed decommissioning following initial mothballing or entombment activities should not exceed more than 60 years, unless it can be shown necessary to protect public health and safety. The Rule appears to discourage the ENTOMB alternative unless specific advantages can be shown. Both the DECON and SAFSTOR alternatives are considered reasonable options for decommissioning light water power reactors. The Rule also requires utilities to perform a periodic review of the funding plan over the life of the facility. TLG Engineering's site-specific cost estimate and decommissioning alternatives are formulated within the framework of the new NRC rule.

Cost and Schedule Estimate Summary for the St. Lucie Nuclear Units Nos. 1 & 2

	Cost, 87$ (Thousands)	Schedule Months
St. Lucie - Single Unit DECON (Prompt Removal/Dismantling)		
Unit No. 1	187,060	72
Unit No. 2	211,223	72
Station Total	398,283	144
St. Lucie Site - SAFSTOR/DECON (Mothball/Prompt Integrated Dismantlement)		
Unit No. 1		
Mothball	22,295	12
5.42 year maintenance cost	14,656	65
Delayed dismantlement	161,356	66
Total	198,308	143
Unit No. 2		
Prompt dismantlement total	195,920	68
Station Total	394,228	154

FPL Witness: Thomas S. LaGuardia
Docket No. 870098-EI
Exhibit _____, Document No. 1

Cost and Schedule Estimate Summary for the St. Lucie Nuclear Units Nos. 1 & 2

	Cost, 87$ (Thousands)	Schedule Months
St. Lucie - Station - Unit ENTOMB (Entombment Integrated Dismantlement)		
Unit No. 1		
Entombment	89,336	36
30 year maintenance cost	8,866	360
Delayed dismantlement	109,784	60
Total	207,986	456
Unit No. 2		
Entombment	106,674	36
24.08 year maintenance cost	7,128	289
Delayed dismantlement	117,037	56
Total	230,838	381
Station Total	438,824	466
St Lucie Station - SAFSTOR (Mothball Integrated Dismantlement)		
Unit No. 1		
Mothball	22,295	12
30 year maintenance cost	65,003	360
Delayed dismantlement	155,065	66
Total	242,364	438
Unit No. 2		
Mothball	22,400	12
24.08 year maintenance cost	52,620	289
Delayed dismantlement	170,104	66
Total	245,124	363
Station Total	487,488	448

Cost and Schedule Estimate Summary for the Turkey Point Plant Units Nos. 3 & 4

	Cost, 87$ (Thousands)	Schedule Months
Turkey Point Plant - DECON (Integrated Prompt Removal/Dismantling)		
Unit No. 3	156,553	72
Unit No. 4	183,948	83
Station Total	340,501	83
Turkey Point Plant - ENTOMB (Entombment Integrated Dismantlement)		
Unit No. 3		
Entombment	79,008	36
29.2 year maintenance cost	7,593	350
Delayed dismantlement	95,905	60
Total	182,506	446
Unit No. 4		
Entombment	84,440	36
30 year maintenance cost	8,739	360
Delayed dismantlement	102,886	56
Total	196,065	442
	378,571	446
Turkey Point Plant - SAFSTOR (Mothball) Integrated Dismantlement)		
Unit No. 3		
Mothball	21,160	12
29.2 year maintenance cost	59,403	350
Delayed dismantlement	133,234	66
Total	213,796	428

FPL Witness: Thomas S. LaGuardia
Docket No. 870098-EI
Exhibit _____, Document No. 2

Cost and Schedule Estimate Summary for the Turkey Point Plant Units Nos. 3 & 4

Unit No. 4		
Mothball	16,595	12
30 year maintenance cost	63,107	360
Delayed dismantlement	150,559	62
Total	230,260	434
Plant Total	444,057	434