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BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. U-16945

LOUISIANA POWER & LIGHT COMPANY

DIRECT TESTIMONY AND EXHIBITS

OF

DANIEL J. LAWTON

DIVERSIFIED UTILITY CONSULTANTS, INC.

ON BEHALF OF

JEFFERSON PARISH

December 1986

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LOUISIANA PUBLIC SERVICE COMMISSION

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PREPARED DIRECT TESTIMONY OF DANIEL J. LAWTON
ON BEHALF OF
JEFFERSON PARISH

Q. PLEASE STATE YOUR NAME.

A. My name is Daniel J. Lawton.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Principal in the firm of Diversified Utility Consultants, Inc.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is 211 E. 7th Street, Suite 727, Southwest Tower Building, Austin, Texas, 78701.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a BA degree in economics from Merrimack College in 1977. In 1978 I received an M.A. in economics from Tufts University.

Q. BRIEFLY DESCRIBE YOUR PROFESSIONAL WORK EXPERIENCE.

A. I have participated in numerous rate proceedings before local, state, and federal regulatory bodies. I have submitted testimony in the states of Louisiana, Minnesota, Indiana, Nebraska, North Carolina, South Carolina, Texas, and also before the Federal Energy Regulatory Commission. A list of the dockets and jurisdictions in which I have testified, along with my resume, is included in Appendix I.

Q. WHO ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am testifying on behalf of Jefferson Parish in this proceeding. Citizens of Jefferson Parish are customers of Louisiana Power & Light Company ("LP&L" or "Company"), and there is a large interest in the outcome of this proceeding as it will affect all LP&L ratepayers. This

case represents a major rate increase to consumers with the proposed inclusion of the Waterford 3 nuclear unit in rate base.

Q. HOW MUCH OF A RATE INCREASE IS LP&L REQUESTING IN THIS DOCKET?

A. As will be discussed later in this testimony, the actual rate request of LP&L in this docket is difficult to determine. Based on the filing of September 23, 1985, LP&L is requesting an increase of approximately $444 million. This translates into approximately a 36% increase in revenue requirements. The base rate increase (after removing the impacts of fuel) is approximately 63%.

As can be seen from the above, the inclusion of the Waterford 3 investment in rate base results in a substantial impact on the rates ratepayers are requested to pay.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF DOCKET U-16945 FROM THE SEPTEMBER 23, 1985 FILING DATE UNTIL THE PRESENT.

A. As I understand the developments in this case, LP&L filed Docket No. U-16945 on September 23, 1985, requesting an adjustment in its rates which would produce $444,398,000 which, after fuel savings of $89,563,000, would result in a revenue requirement of $354,835,000. The rate request was based on a test year of twelve months ending June 30, 1984. The rate increase, if granted, would produce a return of 12.75% and a return to equity of 16.0% on a June 1984 test year.

It should be noted that the LP&L rate request in Docket No. U-16945 (the current case) is essentially the same rate request filed in May 1985 and dismissed by the Louisiana Public Service Commission ("LPSC") in July 1985. The only difference between the current docket and the May 1985

case (Docket No. U-16518) is that the previous docket included a request to recover the Grand Gulf I related expenses.

The September 23, 1985 rate request of LP&L, also, requested that Emergency Rate Relief be granted. In its filing, LP&L indicated the following:

> "Promptly on commercial operation of Waterford 3, LP&L will need increased revenues of approximately $30,000,000 each month. As the commercial operation date of Waterford 3 is virtually at hand, LP&L must request Emergency Rate Relief associated with Waterford 3 by which this Commission would take up, on an emergency basis, the Company's request for rate relief related to Waterford 3 and thereafter permit the Company to implement the rate schedules proposed herein so as to produce $354,835,000 of net additional cash revenues (related to Waterford 3 only) based on a test year ended June 30, 1984. LP&L requests that this Commission then take up the issues of permanent rate relief, but that any decision thereon be prospective only."

Thus, the Company requested not only an increase of $444,398,000, but also requested that the rate increase be implemented immediately on an interim or emergency basis.

Q. DID THE LPSC ACT ON LP&L'S EMERGENCY RATE REQUEST?

A. Yes, they did. In November 1985, the LPSC issued Order No. U-16945 allowing LP&L immediate or interim rate relief of approximately $421 million. In Order No. U-16945, LP&L was allowed immediate rate relief of

A. The first part of my testimony will address the TB&A report and the issue of prudence with regard to the construction of Waterford 3. I have not conducted an independent full-fledged prudence review of Waterford 3, but rather address what I believe to be incorrect and erroneous conclusions contained in the TB&A report.

I will also provide an estimate of what I believe to be the level of a quantifiable imprudence penalty - based on the TB&A report and various responses to Jefferson Parish interrogatories.

Mr. Pous will also be providing a critique of certain parts of the TB&A report, in particular with regard to the continuing justification issue. Also, Mr. Pous will be providing an imprudence quantification associated with the issue of continuing justification.

In addition to the testimony described above, Mr. Pous and I will be providing testimony on the following issues:

1) Depreciation Expense;

2) Impacts of the New Tax Law;

3) Storm Damage Reserves;

4) Amortization of Cancelled Plants and

5) LPSC ORDER No. U-16945

Q. WHAT MATERIAL DID YOU REVIEW IN ANALYZING THE COMPANY'S PROPOSED RATE INCREASE IN REVENUES?

A. I have reviewed the Company's prefiled testimony, exhibits, LP&L responses to intervenors' data requests, annual reports and the Company's direct testimony and exhibits in previous cases before the LPSC.

Q. HAVE YOU REVIEWED ADDITIONAL MATERIAL WITH REGARD TO THE PRUDENCE ISSUE?

A. Yes, I have. Material I have relied upon for my testimony (beyond LP&L responses to Jefferson Parish data requests) on the prudence review is either attached to this testimony or contained in my workpapers.

SECTION I

WATERFORD 3 PRUDENCE OVERVIEW

Q. WHAT TYPE OF PRUDENCE OR RETROSPECTIVE REVIEW HAVE YOU CONDUCTED IN THIS CASE?

A. I have not conducted either a prudence analysis or an independent retrospective review in this case. Rather, I have been asked to review the TB&A retrospective analysis of the Waterford 3 project. Based upon my analysis of the TB&A retrospective review, I have made certain adjustments to their findings of imprudence to arrive at what can reasonably be stated as an imprudence recommendation in this case. As will be shown later, it is my opinion that this Commission should send TB&A back to do further in-depth studies in particular areas so as to be able to assure this Commission and ratepayers that no imprudence on the part of LP&L will result in charges to ratepayers in this and future cases. It is my opinion that TB&A could have done a more complete and in-depth analysis. Whether the results of this report are not complete due to time constraints or budget constraints, I do not know. As is shown later in this testimony, TB&A did not completely respond to the RFP of this Commission. Therefore, it is my opinion that the TB&A report is incomplete, does not address all issues requested by this Commission, and fails to quantify areas of imprudence that may be, in fact, quantifiable. If this Commission were to accept this report i.e., the TB&A report, as a complete and in-depth review of the issue of prudence of Waterford 3, than it is my opinion that ratepayers will be overcharged in their rates because of imprudence on the part of LP&L with regard to Waterford 3.

Q. WHAT WAS THE TB&A APPROACH TO THIS RETROSPECTIVE REVIEW REQUESTED BY THE LPSC?

A. The TB&A retrospective audit was more of an investigation into the organization and management structure of LP&L during the construction of Waterford 3. At page I-4, TB&A states the following:

> "Retrospective or over-the-shoulder audits assess the prudency or reasonableness of past management decisions and actions. The Waterford 3 retrospective audit was an investigation of how effectively LP&L obtained and employed its organization, managerial and system options and resources to minimize - through management - the Waterford 3 cost and schedule, while producing a product of the requisite quality. The emphasis was on the process in place, and the assessment focused on how well those controllable aspects of the project that most significantly impacted costs, schedule and quality were managed."

The above statement represents TB&A's position with regard to their approach to the Waterford 3 audit.

Q. IS IT YOUR OPINION THAT TB&A HAS CONDUCTED A FULL-FLEDGED PRUDENCE REVIEW?

A. No, I do not believe that the TB&A retrospective audit comprises a full-fledged prudence review.

Q. DID THE TB&A REPORT ADDRESS ALL THE ASPECTS OF PRUDENCE SURROUNDING THE CONSTRUCTION OF WATERFORD 3 THAT WERE REQUESTED BY THIS COMMISSION?

A. It appears that the TB&A "Retrospective Review" falls short of answering all the questions that the LPSC wanted addressed in the prudence review.

While Mr. Pous addresses, in his testimony, some of the areas that need to be examined in a full fledged prudence review, there are a number of other areas I will address below.

Two documents are very important in showing that TB&A appears not to have completed all the LPSC requirements for the prudence review. The first document is the LPSC Request For Proposal ("RFP"), while the second document is a letter to TB&A from the LPSC Secretary Louis S. Quinn. Both of these documents are contained in my testimony as Exhibit ____, Schedule (DJL-2 and 3), respectively. Both the RFP and the Louis Quinn letter specifically address the areas of continuing justification. In particular, the Louis Quinn letter states:

> "...the Commission wants to be advised as to the basis on which the decision was made to continue to construct Waterford 3. Your report should cover the least cost life cycle economic analysis of building nuclear, coal, lignite, etc. as part of your economic analysis of the LP&L decisions made at various times to continue to build the nuclear generating plant."

With regard to this issue of continuing justification, TB&A never did conduct an economic analysis of the LP&L decisions made at various times to continue to build the nuclear generating plant, despite the specific request from the LPSC in the Louis Quinn letter dated May 1, 1986.

TB&A appears to have relied upon the LP&L documentation of more than two dozen studies and analyses that considered the economics of using nuclear power versus the use of alternative fuel sources in the LP&L

service area. Mr. Pous discusses the particular problems with these studies in his testimony. The following are some of the TB&A conclusions relative to the TB&A review of these alleged continuing justification studies:

> "Review of these studies and analyses revealed that a full scale study to specifically examine the economics of Waterford 3 vis-a-vis other options was never conducted after the initial decision to build the plant."

Further, at page III-65 of the TB&A report, it is concluded that:

> "While the analyses that were conducted would allow LP&L management to infer that nuclear economics were still favorable to other options, there was no specific least cost life cycle analysis conducted during the construction of Waterford 3."

What TB&A fails to note is that ratepayers should be provided more than an inferrence concerning nuclear economics, when it is the ratepayer who is being asked to pay for approximately $3 billion of investment by LP&L.

TB&A goes on to state the following:

> "Such a re-examination would have been particularly warranted prior to the start of construction on Waterford 3 after the lengthy delay and project cost escalation following the antitrust proceedings."

Thus, even though TB&A believes that the decision to build Waterford 3 should have been re-examined in the 1974-1975 time frame and keeping in

mind that the LPSC requested that TB&A conduct such an analysis (Quinn letter dated May 1986), TB&A did not address this aspect of the continuing justification question. Rather, TB&A relied upon generic rather than Waterford 3 site specific results to justify the continued construction of the nuclear option. Lastly, at page III-66, TB&A concludes the following:

> "While the Company did conduct periodic economic justification of nuclear power, studies were not made using specific to-go costs of Waterford 3, nor were least cost life cycle analyses performed. The periodic economic studies that were made did imply that continuation of construction was justified."

Again ratepayers and this Commission need more than a mere implication of nuclear economics where a $3 billion investment is concerned.

Q. WHY IS TB&A INCORRECT IN RELYING ON THE REFERENCED STUDIES RATHER THAN CONDUCTING A SITE SPECIFIC LEAST COST LIFE CYCLE STUDY FOR THE CONTINUED JUSTIFICATION OF WATERFORD 3?

A. Aside from not complying with the LPSC requirement of conducting an economic analysis of the LP&L decisions made at various times to continue to build Waterford 3, reliance on the referenced studies is misplaced for two reasons. First, as Mr. Pous will show in his testimony, the studies, in fact, relied upon are incomplete and, given LP&L's cost estimates, some of the studies cannot be relied upon. Second, if the referenced studies are, in fact, a reliable basis for continued construction of the nuclear option, then LP&L has no basis for cancelling the St. Rosalie project.

Q. PLEASE EXPLAIN WHY LP&L WOULD HAVE NO BASIS FOR CANCELLING THE ST. ROSALIE NUCLEAR PROJECT IF THE REFERENCED STUDIES WERE, IN FACT, RELIED UPON.

A. If TB&A is correct in its reliance on the referenced studies which show the nuclear option is superior to alternate fossil-fueled generation, then LP&L, or at the very least MSU, were imprudent when they decided to cancel the St. Rosalie nuclear project in 1975. It does not make sense to cancel the least cost alternative as was allegedly shown by the referenced studies. TB&A's conclusions imply that MSU, and possibly LP&L, selected the more costly planning alternative when the St. Rosalie project was cancelled. It would appear that even LP&L did not always believe these referenced studies that were relied upon by TB&A for its conclusions.

Q. ARE THERE OTHER ASPECTS OF THE LPSC REQUEST FOR PROPOSAL THAT TB&A DID NOT ADDRESS?

A. Yes. TB&A did not fully address the issue of whether the initial decision to build Waterford 3 was a well-planned decision. TB&A appears not to have considered the impact on the final cost estimate of the Waterford No. 3 project of Nuclear Regulatory Commission decisions and/or inspections. TB&A failed to make a determination of whether or not additional costs associated with regulatory changes and requirements could have been avoided by anticipating the changes through proper oversight responsibility.

Q. WITH REGARD TO THE TB&A REPORT, WHAT AREAS OF THAT REPORT WILL YOU BE ADDRESSING?

A. Given time and data constraints, I will be addressing what I believe to be the most important aspects of the TB&A report. I will provide what I

believe to be a more accurate quantification of imprudence with regard to LP&L's Waterford 3 project based on the TB&A report and data I have.

The areas of the TB&A report I will be addressing are as follows:

A) TB&A Assumptions and Guidelines

B) Contract Strategy

C) Cost and Schedule Control

D) Financial Management

E) Licensing

F) Outside Audits

G) TB&A's Imprudence Quantification Approach

H) Summary and Findings

SECTION II

PRUDENCE DEFINITION

Q. PLEASE DESCRIBE THE CONCEPT OF PRUDENCE AND IMPRUDENCE WITH REGARD TO REGULATION.

A. The disallowance of cost associated with imprudent actions is a fundamental requirement of traditional regulation. Disallowances resulting from imprudent actions are a fundamental part of the responsibility given to a regulatory body when setting reasonable rates for utility services. This charge of ensuring that all costs are prudently incurred is necessary to protect the ratepayer from being charged escessive rates by public utilities. If, for example, in a competitive market a firm tried to impose on its customers a higher price because of cost from imprudent actions, the customers could take their business to a more efficient provider of the same service at a lower price. On the contrary, utility ratepayers have no such choice to go to an alternative provider of the same service. Monopolies are granted franchises and therefore monopoly rights with regard to utility services.

Utilities must be motivated to act in a prudent fashion by the threat that the prospect of imprudently incurred cost will, in fact, be disallowed by the regulatory body. Therefore, regulatory bodies have as an obligation the responsibility to impose such disallowances on utility investments when such disallowances are warranted i.e., when such investments are imprudently incurred.

Q. WHAT DEFINITION OF PRUDENCE, IN YOUR OPINION, SHOULD THIS COMMISSION FOLLOW WHEN EVALUATING THE RECORD IN THIS DOCKET?

A. In evaluating prudence in this case, the Commission must determine whether the Company acted reasonably under all the circumstances at the time the actions in question were taken. Clearly, the investors of LP&L should receive reasonable protection for all investments made by LP&L that were prudently incurred and which were dedicated to serve the public. Investors should not be penalized by applying hindsight to decisions or actions that were reasonable at the time the decisions were made. The Commission, when applying the reasonableness standard noted above, should also require that LP&L be held accountable if it is determined that LP&L, in fact, failed to respond adequately to changing circumstances or to new challenges as the Waterford 3 project progressed. Ratepayers of LP&L are entitled to protection from the consequences of unresponsive or imprudent management and decisions. Therefore, there are two parts to the equation with regard to prudence. On the one hand, one should not use hindsight, but also one should protect ratepayers from the Company's failure to respond adequately to changing circumstances. By following both parts of the equations, the Commission can ensure that the rates set are truly just and reasonable.

In summary, the Company's conduct should be judged by considering whether the conduct was reasonable at the time, under all the circumstances, considering that the Company had to solve its problems prospectively rather than with the reliance of hindsight. Further, while industry norms may, in fact, be helpful in looking at a particular situation with regard to cost, planning, etc., these industry norms are merely one indication of whether the Company's responses to its problems

were reasonable at the time. Industry norms cannot be relied upon as the deciding factor when determining whether the Company was responsible in its judgment. For example, industry norms in the nuclear industry may only indicate that Waterford 3 costs are higher than average in a very flawed industry.

Q. DOES THE COMPANY HAVE A STANDARD OF PRUDENCE WHICH IT HAS PUT FORTH IN THIS CASE, DOCKET NO. U-16945?

A. It appears that the Company's position on prudence is set forth in the statement of James M. Cain, dated November 12, 1986. Mr. Cain is President and Chief Executive Officer of LP&L and has held that position since 1983. At the first page of his statement Mr. Cain states:

> "Nobody is perfect. However, what I am saying is that, looking at this whole subject without exersizing hindsight and gauging our conduct on the basis of prudence being the conduct of a reasonable person who is qualified to do the job, there certainly should be no finding of imprudence."

It would appear that Mr. Cain believes that the prudence standard for this Commission to follow should be that anybody in his right mind who was hired by LP&L and makes a decision should always be found to be prudent in that decision making process. Mr. Cain's standard would find nothing wrong with LP&L turning over all its authority of oversight of the Waterford 3 project to the contractor engineer, architect-engineer, Ebasco. Further, Mr. Cain's standard would totally ignore the fact that a company should be imprudent if it gave the decision to construct and go ahead with the unit to an architect-engineer. LP&L's standard put forth

in this November 12 statement is totally unworkable in the framework of regulation and the regulatory process, and again would result in no commission being allowed to ever determine imprudence, because, Mr. Cain ignores the fact that qualified reasonable people sometimes make imprudent decisions.

Q. DID THE COMPANY PUT FORTH THE CASE OF PRUDENCE WITH REGARD TO WATERFORD IN THIS DOCKET?

A. No, the Company has not put forth a case showing prudence with regard to the construction, continuing justification, and final cost of the Waterford 3 project. Mr. Cain, under cross-examination, indicated that the Company felt it did not need to put forth a case on the matter of prudence of Waterford 3. Further, Mr. Cain, under cross-examination, indicated that it is not the Company's i.e., LP&L's burden to show prudence, but rather, the Commission and intervenor's burden to show imprudence. Clearly, Mr. Cain is attempting to shift the burden of proof in this matter when it rightly belongs with the Company.

Therefore, there is no record evidence from LP&L or its parent MSU which shows that the Waterford 3 project was prudently constructed, managed, or whether, in fact, the nuclear option should even have been selected.

Q. DID MR. CAIN HAVE ANY COMMENTS WITH REGARD TO THE TB&A RETROSPECTIVE REVIEW OF WATERFORD 3?

A. Yes, Mr. Cain had a number of comments with regard to the TB&A report. For example, in his November 12, 1986 statement, Mr. Cain states:

"I am, and LP&L is, particularly aggrieved by any conclusion that LP&L has been imprudent, in any respect, and, particularly, imprudent to the extent of $143 million."

Mr. Cain further states:

"I am not saying that LP&L has been perfect in its planning and construction of Waterford 3. Nobody is perfect."

Yet, Mr. Cain does not feel justified in putting forth the case with regard to explaining the imperfections and associated cost increases of LP&L on the matters of construction and planning of the Waterford 3 project. Mr. Cain further indicates at page 3 of his statement that LP&L is criticized for maintaining its tradition of having a lean staff. Mr. Cain ignores the fact that the TB&A report finds that the LP&L tradition of lean staffing was not appropriate with regard to not only the new technology of the nuclear option undertaken by LP&L, but also with regard to an investment which turned out to be approximately $2.84 billion. Further, Mr. Cain ignores the fact that LP&L's own consultant, Management Analysis Company ("MAC"), criticized LP&L for its lean staffing approach. While the management and oversight role of this $2.84 billion investment in Waterford 3 may have been lean, the expenditures on the Waterford 3 project were far from being lean. This policy of lean-ness will be discussed later in this testimony.

SECTION III

TB&A'S ASSUMPTIONS

Q. DO YOU HAVE ANY COMMENTS WITH REGARD TO THE UNDERYLING ASSUMPTIONS EMPLOYED BY TB&A WITH REGARD TO THE RETROSPECTIVE REVIEW ON WATERFORD?

A. Yes, I have a number of comments. First, the overall assumptions employed by TB&A are conservative in favor of LP&L rather than being balanced between the ratepayer and the Company. In my opinion, the underlying assumptions employed by TB&A and guidelines used in the retrospective review resulted in the findings favoring LP&L, and such assumptions were not balanced with regard to a prudence determination. One assumption used by TB&A, to which I agree, is as stated at page I-4:

> "We adhere to our belief that the assessment must be made without falling into the trap of hindsight, and that the outcome of a specific decision, action or sequence of actions is not the proper indicator of the reasonableness of management's action."

While I do, in fact, agree with TB&A that hindsight should not be employed in a case for the determination of prudence, TB&A, in fact, violated this assumption in a number of places in its report to support its conclusions. For example, at page VIII-10, TB&A states:

> "Exhibit VIII-5 shows an LP&L comparison of project capital costs for various single and first-of-two units with commercial operation dates within eighteen months of the Waterford 3 commercial operation date of September 1985. The average capital cost, including AFUDC, of the nineteen

plants in this sample (excluding Waterford 3) is $3475 per kilowatt capacity. On this basis, the $2572 per kilowatt capital cost of Waterford 3 is 26 percent less than this average and appears to compare quite favorably."

On that same page, it is further stated:

"Here the Waterford 3 cost of $2015 per kilowatt is very near the average cost of $1988 per kilowatt. When compared on this basis, the cost performance of Waterford 3 is average for contemporaneous plants of this type."

Such conclusions and inferrences made by TB&A can only made with the use of hindsight. This is in direct violation of one of their basic assumptions. It appears that TB&A uses hindsight when it favors LP&L, but when hindsight is used to work against LP&L, TB&A sticks by its original assumption.

An additional comment with regard to TB&A's comparison of Waterford 3 to other nuclear projects at Exhibit VIII-6 is warranted. TB&A compares Waterford 3 costs to the costs of eight other nuclear units. Five of the units in the comparison have had imprudence findings against them by various regulatory commissions. Two of the units are not yet complete, but with regard to one of the two, Seabrook 1, there has been substantial controversy regarding its construction. It is also my understanding that the regulatory commission in North Carolina will be conducting an in-depth prudence review of the Harris Unit 1.

All one can conclude from this comparison is that TB&A has included a comparison of many units that have had imprudence findings to compare to

LP&L's Waterford 3 unit. Yet, TB&A never mentioned in its report that it was comparing Waterford 3 to nuclear units that other regulatory commissions had considered partially imprudent.

Q. WHAT TB&A ASSUMPTIONS APPEAR TO BE BIASED IN FAVOR OF LP&L?

A. Another assumption used by TB&A is as stated on page I-4:

> "Similarly, the mere existence of one or more errors on the project attributable to either owner or contractor actions does not in itself signify unreasonableness or imprudence. The existence of a large number of errors or the generic nature of a specific error or group of errors, however, would be cause for suspecting unreasonable management actions."

This assumption is obviously biased when one looks at the quantity of errors in enumerating a decision of imprudence. One should not review the quantity of errors, but rather the magnitude of any error and its impact on the project. Clearly, if TB&A follows this assumption to the extreme and one error results in $1 billion of imprudence, then TB&A could indicate that since this is only one error, it is not sufficient to justify or suspect imprudence. Obviously, one must look at the magnitude and nature of the error in addition to the absolute quantity of errors made. Also, numerous errors, even under TB&A's approach, should lead to more than a mere suspicion of imprudence.

Q. WERE THERE ANY ADDITIONAL ASSUMPTIONS OF TB&A IN WHICH YOU DISAGREE?

A. Yes, there were. In particular, the assumption of what I refer to as the "critical path" assumption employed by TB&A was biased in favor of LP&L,

and it is my opinion that it could result in significant dollars of imprudence not being quantified or addressed in this retrospective review. The critical path assumption to which I refer is TB&A's basic position or premise that so long as a task, although it may be imprudent, did not change the critical path of the project, then there is no quantifiable imprudence. In other words, if a task was imprudently managed by LP&L and resulted in delay, but if at the same time other factors outside LP&L's control were occurring which also slowed or delayed the project, the imprudent task would not be quantified given that these other factors would have delayed the project anyway. Taking this assumption one step further, TB&A is basically concluding that if a task takes two or three times as long as it should have, there is no quantifiable imprudence associated with this task if, at the same time, external factors outside the control of LP&L were occurring which would have delayed the project anyway. Clearly, any task which takes two or three times as long as it should will likely result in higher costs for that task. It appears that TB&A did not review items which were off the critical path, even if the tasks (off the critical path) were imprudently managed.

Q. CAN YOU SITE ANYWHERE IN THE TB&A REPORT WHERE THIS ASSUMPTION IS RELIED UPON IN THE ANALYSIS?

A. Yes, I can. At page E-5 of the report, TB&A states the following:

> "It was not reasonable, however, to fail to use the delay to develop detailed schedules and acceptable bidding documents for the priority construction contracts. Rather

than waiting until the CP was received in November 1974, LP&L should have authorized Ebasco to proceed with a detailed cost and schedule estimate when the LWA was received in July 1974. This would have allowed the project to get off to a strong start when the construction permit was granted. Instead, TB&A found, LP&L and Ebasco were not ready. It took until May 5, 1975, five and one-half months after receipt of the CP, to issue the request for bid on the concrete contract. This contract was identified in early schedules to be on the critical path for the project. TB&A's schedule analysis found that problems with the site dewatering and excavation, which were outside LP&L's control, negated the impact of the concrete contract delay. Had these problems not occurred, however, LP&L's inaction would have delayed the project four months."

This is a perfect example of how TB&A's critical path assumption is used. TB&A concluds that because of problems with site dewatering and excavation, the delay in establishing the concrete contract i.e., the imprudence on LP&L's part with regard to this contract, had no impact on the overall schedule. However, TB&A did not determine whether the five and one-half month delay in the procurement of a concrete contract resulted in procuring a higher cost concrete contract than would have been negotiated five and one-half months earlier. Further, on page E-5, TB&A notes the following:

> "LP&L's continued attempt to get fixed-price contracts resulted in delays due to having to rebid the work when no or unacceptable bids were received. Delays of up to five months in the issuance of contracts occurred as a result. Project delays beyond LP&L's control in the concrete work, however, lessened the importance of the contract delays. Nonetheless, TB&A concludes that the unreasonable contracting strategy contributed to a construction completion delay."

TB&A now concludes that because the concrete contract was delayed because of both imprudence on LP&L's part, and also external factors (dewatering and excavation outside of LP&L's control), most of the contract delays that followed were not found to be imprudent because the critical path had been delayed given the timing of the concrete contract. It does not appear that any investigation as to whether the delay in such contracts resulted in higher cost contracts was ever conducted or investigated by TB&A.

A third area where this assumption of critical path has affected prudence findings is shown on page VIII-6, where TB&A states the following:

> "TB&A believes that if it had, perhaps the LP&L finance group could have found additional funding to keep the project on track. TB&A finds that LP&L did utilize conventional external markets to the extent reasonable in an attempt to finance the project and prevent the 1980 manpower reduction. In addition, TB&A finds that LP&L had

tried to expedite the NRC licensing review process, had not succeeded and was concerned that Waterford 3 would be completed a year in advance of being able to receive an operating license. Based on these two findings, no impact has been assessed in this area."

Once again, we have a situation where the project was slowed down and the labor force was cut from 3,000 to 2,000, yet any increase in the overall cost due to the finance cutback was not found to be imprudent because at the same time LP&L was struggling to get an operating license and, therefore, the critical path was the procurement of the operating license from the NRC. TB&A has concluded that because the operating license was not yet attained, the financing delay had no impact on the cost of the unit. It should be noted in the section of my testimony where I address cost scheduling and its impacts on financing that, cost increases were the result of the financing delay as evidenced by the Company's own documents, and TB&A did not attempt to quantify imprudence associated with the cutback in 1980 or the cutback in 1977.

Q. DO YOU AGREE WITH TB&A'S ASSUMPTION THAT IF THERE IS NO QUANTIFIABLE IMPACT ASSOCIATED WITH AN AREA OF IMPRUDENCE THEN RATEPAYERS ARE NOT HARMED?

A. Yes, I do agree with that assumption. Clearly, if an area of imprudence does not lead to increased cost to ratepayers then, in fact, ratepayers have not been harmed. I do not agree with TB&A's assumptions that if external factors out of LP&L's control were affecting the critical path of the project, that there is no imprudence associated with the task because

the task is not on the critical path. TB&A appears to require a very high standard before it will even attempt to quantify dollars associated with an action found to be imprudent. For example, at page I-6, TB&A states the following:

> "TB&A recognized early in the evolution of performing retrospective reviews of nuclear power plant construction projects that a difference in two numbers - a difference between estimated and actual costs, for example, or a deviation from industry average costs, is not in itself sufficient cause for either a charge of unreasonableness or a defense of reasonableness. Even making adjustments to allow "apples to oranges" comparisons - to take into account factors unique to a project - does not eliminate the need to first demonstrate the fundamental nature of the unreasonableness. Only then can cost impacts be quantified."

TB&A appears to have a more stringent standard than is necessary from a ratepayer's, regulatory body or even a utility perspective. Clearly, if the Company is found to be imprudent in its actions, and if a quantification of such imprudence can be made, then the Company should be penalized for the imprudent actions. If for example, a Company's actions are found to be unreasonable, then the demonstration of the fundamental nature of that unreasonableness is not necessary. The Company should be required to be reasonable at all times in all actions.

Q. IS THERE ANY EVIDENCE TO SUGGEST THAT THE TB&A CONSERVATIVE ASSUMPTIONS MAY IN FACT LEAD TO LACK OF IMPRUDENCE FINDINGS IN THEIR STUDIES?

A. Yes, there is. For example, TB&A worked for Southern California Edison Company ("SCEC") in the capacity of litigation support on the San Onofre nuclear generating station ("SONGS") prudence study. In that case, SCEC was defending itself in a prudence case before the California Public Utility Commission. SCEC did not believe it was imprudent in the construction of SONGS and hired TB&A for assistance, the Commission did conclude a substantial imprudence finding very recently of approximately $350 million. It should be noted that under cross-examination, TB&A witness Resh indicated that TB&A did not advise SCEC whether there was imprudence that might, in fact, be quantified.

Another project worked on by TB&A staff was the South Texas Project before the Public Utility Commission of Texas with regard to prudence associated with STP 1 and STP 2, and the determination of whether CWIP should be placed in rate base. Under Texas law, a company that requests CWIP in rate base must first show that the CWIP dollars were prudently incurred and that CWIP in rate base is necessary for financial integrity. Therefore, the State of Texas has a twofold test i.e., one of financial integrity and, secondly, one of prudence. The TB&A staff witnesses who conducted the study testified before the Public Utility Commission of Texas on behalf of Houston Lighting & Power Company and concluded that STP was, in fact, prudent. The Commission in that case concluded that the Company had not made a showing of prudence with regard to STP and, therefore, disallowed any CWIP in rate base. The TB&A approach as shown

in the Waterford study is, in fact, very conservative and biased in favor of LP&L, and should be looked at in this regard.

SECTION IV

CONTRACT STRATEGY

SELECTION OF AN ARCHITECT-ENGINEER AND CONSTRUCTION MANAGER

Q. DO YOU HAVE ANY COMMENTS WITH REGARD TO LP&L'S SELECTION OF EBASCO AS THE ARCHITECT-ENGINEER FOR THE WATERFORD 3 PROJECT?

A. Yes, I have a number of comments. At page II-8 of the TB&A report, a discussion of LP&L's determination and decisions with regard to the selection of the architect/engineer ("A/E") is shown. Although discussions were held between LP&L and other potential contractors (but no records of these discussions were made and no proposals were made), LP&L ultimately selected Ebasco.

TB&A further notes:

"Apparently, LP&L did not seriously consider contracting with anyone other than Ebasco to engineer and manage the construction of Waterford 3. This reliance on a sole source of these services was predicated largely on a long and (in LPL's judgment) successful relationship between Ebasco and LP&L."

TB&A further notes:

"In the absence of competitive proposals for this contract, TB&A proceeded to evaluate the Ebasco contract against contemporaneous contracts that we have studied in other nuclear retrospective reviews."

Thus, LP&L did not put the Waterford 3 job out to competitive bid, and TB&A merely evaluated the Ebasco contract against contemporaneous

contracts to determine whether the Ebasco contract was reasonable.

Q. WHAT DID TB&A CONCLUDE WITH REGARD TO THE EBASCO CONTRACT AND THE BIDDING PROCESS?

A. At page II-11, TB&A concludes the following:

> "First, as to the selection of Ebasco to provide AE/CM services, we find that although the process was noncompetitive, Ebasco was a reasonable choice. This conclusion is based largely on the combination of Ebasco's qualifications and its strong past relationship with LP&L."

LP&L did not put the project out to bid, a major project estimated to cost some $230 million in 1970. If a project is put out to bid, even if LP&L planned to select Ebasco as the A/E, then possibly, Ebasco might have "sharpened its pencil" in the bidding process, knowing full well competitors also would be submitting bids to LP&L for the same project. Clearly, any time a job is put into the competitive marketplace, the competitive market conditions will result in a fair market price. Apparently, LP&L did not feel that the market forces were necessary to get a reasonable price. TB&A apparently did no investigation as to whether the final estimate or contract was reasonable and, as a matter of fact, they concluded that relative to other contemporaneous contracts, the fixed-fee provisions were not reasonable. Yet, TB&A was unable to quantify an impact associated with this area of poor judgment on the part of LP&L. Obviously, ratepayers would be impacted if a contract could have been procured at a lower price or other contract concessions could have been negotiated.

SECTION V

COST ESTIMATES

Q. DO YOU HAVE ANY COMMENTS WITH REGARD TO THE TB&A REVIEW OF THE LP&L COST ESTIMATES AND SCHEDULING?

A. Yes, I have numerous comments concerning TB&A's analysis, conclusions and use of those conclusions, regarding cost estimates. First, with regard to cost estimates, such estimates are very important in the process of any project. The initial estimates, and continued reevaluation of the investment necessary to complete a project, are vital to the decision-maker in making the determination of whether to continue the project. Secondly, such estimates are very important to the determination of ability to finance the project. Clearly, LP&L's financing department needed accurate cost estimates so that the financing of this project could go forward on a timely and efficient manner. The most important aspect of all the estimating of the Waterford 3 costs is the factor that the estimate must be as accurate as possible so as to evaluate the economics of the project.

In the TB&A report at page III-36, TB&A notes:

"Ebasco was responsible for preparing cost estimates. LP&L supplied its own estimates for LP&L-specified costs. The baseline estimates were originally prepared in the Ebasco New York office. Later forecasts were prepared in the Ebasco field office, where most of the necessary cost data was available. Most of the construction cost forecasting was done utilizing manual techniques based upon actual

dollar expenditures and data derived from the computerized Project Quantity and Manpower Report."

Once again, becuase of LP&L's inexperience and lean staffing, LP&L, in fact, relied upon its A/E for cost estimates as well as schedule estimates. But, LP&L appears to have ignored its oversight role as well as its responsibility with regard to ensuring accurate estimates for project cost. The inaccurate estimates that resulted, and discussed below, during the Waterford 3 project may have caused the project to continue when, in fact, more accurate estimates combined with a site specific economic analysis would have indicated the project was not a viable alternative.

Q. WHAT, IN FACT, WERE THE ORIGINAL COST ESTIMATES, AND HOW MANY TIMES DID THESE ESTIMATES CHANGE OVER THE LIFE OF THE CONSTRUCTION PROJECT?

A. The detailed cost estimates provided by Ebasco in conjunction with LP&L at various points in time from the 1970 initial estimate to the final cost estimate in 1985 are shown in TB&A's Exhibit III-17. As can be seen from this schedule, the Waterford 3 cost estimates were changed fourteen different times above and beyond the initial or conceptual estimate. The initial estimate when the project was announced in November 1970 was what is referred to as an order of magnitude proposal estimate by Ebasco which TB&A indicates was based upon Ebasco's previous experience in the industry. This estimate for the Waterford 3 project was $230 million for an 1100 megawatt unit. This translates into an estimate of approximately $209 per kilowatt of capacity investment for the nuclear project.

The first detailed preliminary project estimate was prepared by Ebasco and supplied to LP&L in March 1973. Ebasco's estimate at this point was $445 million, which included a 14% contingency, and was based upon 58% of the engineering being completed. It appears that the 14% contingency allowance was for capital cost estimates, quantity variances, design refinement, pricing errors, craft labor performance and escalation.

Thus, the initial estimate of $230 million increased by approximately 93% based upon the preliminary project estimate which was more site specific and contained much of the preliminary engineering work being completed.

At page III-36 of the TB&A report, the following is noted:

> "LP&L did not authorize Ebasco to perform a detailed estimate until after receipt of the CP. LP&L thought the potential for extended delays in the antitrust proceedings created sufficient uncertainty to delay the estimate preparation."

One must wonder how fruitful LP&L's position was given that a true detailed cost estimate prepared in this time would be a good indicator of whether the project should go forward, or not, after the CP was granted. This time could have been spent in analyzing the true costs of constructing the Waterford 3 project and comparing them to other alternatives. This is especially true in light of the antitrust proceedings that were going on and the problems LP&L appeared to be having with regard to the licensing of the Waterford project. Had not the Waterford 3 project been granted a license by the NRC, LP&L should have

been in a position to consider all least cost alternatives. At the same page, TB&A goes on to note:

> "LP&L requested Ebasco to perform a detailed estimate in November 1974. An order of magnitude $710 million estimate was developed in December (there was not sufficient lead time to have detailed backup) and approved by LP&L."

It is further noted that:

> "Despite the fact that the schedule had been extended fourteen months (although it hadn't been officially approved until December 1975) LP&L again approved a $710 million estimate for Waterford 3 in October 1975. In August 1975 internal LP&L memorandum had pointed out that the estimate was based on an out-of-date schedule and on old purchase orders which hadn't been updated to reflect new site need dates. The new construction schedule was reviewed with LP&L in December 1975. It showed a fourteen-month slip in the commercial operation date. Ebasco estimated a total project cost of $800 million based on this schedule."

Thus, we have LP&L using cost estimates which were known to be out-of-date, based upon schedule delays, and were low by a substantial factor due to the fact that the schedule had slipped in excess of one year in one case. Yet, LP&L insisted on using out-of-date information in estimating the cost of the project.

Rather than have Ebasco provide a detailed cost estimate which Ebasco indicated to LP&L would cost approximately $100,000 to prepare a definitive estimate in 1976, LP&L found this prohibitive and used the December 1975 estimate as the basis for its $815 million cost estimate which was approved in September 1976 and again in 1977. A contingency of 14% for to-go costs was included. It should be noted that the cost of $100,000 for a new definitive estimate was equivalent to approximately 0.01% of the current overall cost estimate during that time period.

Q. DOES THIS MEAN THAT LP&L NEVER HAD A DEFINITIVE COST ESTIMATE FOR THE WATERFORD 3 PROJECT THAT WAS ACCURATE FROM ITS INITIAL ESTIMATE IN NOVEMBER 1970 UNTIL AT LEAST JULY 1978?

A. Yes, that is correct. Based upon the TB&A report, LP&L never had a definitive detailed cost estimate which took into consideration schedule slips and delays for the period November 1970 until July 1978.

Q. HOW MUCH MONEY WAS EXPENDED ON THIS PROJECT WITHOUT A DEFINITIVE ESTIMATE OF WHAT THE FINAL PROJECT WAS GOING TO COST DURING THIS EIGHT-YEAR PERIOD?

A. Approximately $600 million including AFUDC was expended on the project between 1970 and July 1978. Also, based on the facts set forth in the TB&A reports, the Company issued bonds, preferred stock and equity to finance its Waterford 3 endeavor without knowing the full cost and fully knowing that tht estimates of cost that it was, in fact, relying on were inaccurate and based upon out-of-date information, as well as knowing that schedule slips had occurred, yet were ignored by LP&L. All LP&L knew in 1978 was that it had spent approximately 2-1/2 times the initial $230

million estimate without knowing how much it had to go as far as completing the unit.

Q. WHEN WAS THE FIRST DEFINITIVE COST ESTIMATE MADE?

A. It appears that the first definitive cost estimate was issued in August, 1978. At page III-37 of the TB&A report, the following is stated:

> "Ebasco considered an estimate to be definitive when it was done after the completion of piping detailed drawings. A definitive estimate which was internally consistent was not prepared and approved for Waterford until mid-1978. LP&L reviewed it in March 1978 and requested changes. Revisions were made and a definitive estimate was issued in August 1978. The $1.11 billion estimate was based on a May 1981 fuel load date. The absence of an overall schedule that included the then-current eight-month schedule delay meant that certain assumptions had to be made."

Once again, the first definitive estimate was made by Ebasco in August 1978, but it appears that an eight-month schedule delay was not included in that estimate and, therefore, certain assumptions had to be made. Thus, there is still no estimate made that includes all the impacts that are going to occur with regard to the Waterford 3 construction project. Another point that should be made is that the first definitive $1.1 billion estimate made in August 1978 was similar to the $1.1 billion cost for each of the St. Rosalie units in 1975, which was cancelled because of its enormous cost. Yet, it does not appear that LP&L made any consideration with regard to cancelling the Waterford 3 unit because of

what appeared to be an increase from the conceptual estimate of approximately 4.8 times.

Q. WHAT WERE TB&A'S CONCLUSIONS WITH REGARD TO THESE COST ESTIMATES FOR THE WATERFORD 3 PROJECT?

A. At page III-38 of the TB&A report, the following is stated:

> "LP&L started construction with only a conceptual estimate in place, despite the fact that Ebasco was 50% complete with engineering. TB&A finds this neither typical nor reasonable. After Ebasco developed the detailed preliminary estimate in 1975, LP&L did not authorize Ebasco to do another one until 1978. LP&L maintained and approved the same cost estimate at one point in this time frame despite a significant schedule slip. These actions are also unreasonable in TB&A's view. After 1978 the Waterford 3 cost estimating practices improved. LP&L began to make a serious effort at developing its portion of the cost estimates, and annual updates of the total estimates were made which appropriately considered actual project conditions. The accuracy of LP&L's portion of the cost estimates suffered, however, until 1982 when it had detailed plans of the total work required to do the job. As discussed in Chapter VIII, Section B, TB&A did not find a quantifiable impact associated with this area of imprudence." (Emphasis added)

It appears that TB&A would agree that LP&L's inexperience and lack of care with regard to a reasonably accurate cost estimate was imprudent on the part of the Company. One can also conclude that LP&L did not truly have any idea what the total project cost would be given its lack of a detailed cost estimating until 1982. Therefore, the Company expended approximately $1.8 billion over a 12-year period before it endeavored to seriously develop a detailed cost estimate of the total project cost. It should be noted that LP&L finally took the cost estimating process seriously at a point in time when the project costs were approximately $1.6 billion more than the total project was supposed to cost initially.

Q. TB&A CONCLUDES THAT THERE IS NO QUANTIFIABLE IMPACT RELATED TO THIS IMPRUDENCE ON LP&L'S PART. DO YOU AGREE?

A. No, I do not. LP&L's imprudence led to many problems with regard to the Waterford 3 project. First, given that there were no detailed cost estimates or attempts made to develop a detailed cost estimate for the majority of the Waterford 3 construction period, there was no basis for LP&L to ever conclude during this project throughout the 1970's whether LP&L's Waterford 3 was an economically viable alternative to other sources of generation such as coal. In other words, to do a least cost life cycle analysis or any other type of analysis, one would have to have some idea of what the investment cost for the nuclear alternative. For example, LP&L claims when it realized what St. Rosalie was going to cost, it immediately cancelled the unit. Further, even when it did authorize cost estimates, it still chose to ignore or try to adjust for known schedule slips which would negate the accuracy and, thus the dependability, of any

cost estimate developed. LP&L, as is obvious from the above, had no idea what the cost for the Waterford 3 project would be given that they did not attempt to do a detailed cost analysis which considered all known circumstances. As can be seen on Exhibit III-41, pages 1 through 6, of the TB&A report, TB&A relies upon numerous studies that were done to justify the continued construction of the Waterford 3 project. Many of these studies were LP&L site specific studies with regard to the Waterford 3 project versus coal. None of these studies can be considered reasonable or accurate given the fact that LP&L did not have a reasonable cost estimate for the capital investment for Waterford 3. Therefore, it must be concluded that LP&L's imprudence with regard to the cost estimating process led to providing misleading information with regard to the continuing economic justification studies.

Q. WHAT OTHER PROBLEMS HAS LP&L'S IMPRUDENCE WITH REGARD TO COST ESTIMATING LED TO WITH REGARD TO THE WATERFORD 3 PROJECT?

A. A major area of concern would be with regard to the financing of the project. As TB&A has concluded in this report, and as I will discuss later, the financing of the project requires the knowledge of how much the project will cost and when specific amounts are required so that a determination of the financing needs can be made. Clearly, the Waterford 3 project was estimated to be a large and costly project i.e., larger than any other endeavor undertaken by LP&L. Given the above, for the financing department to truly budget, project and estimate timing of financings, the availability of funds, etc., one would need a detailed cost estimate or some idea of what this project was going to cost the Company, and

ultimately the ratepayers. Given that the financing department was never provided accurate or reliable cost estimates, because of the cost estimating imprudence, the financing endeavor was troubled. For example, as is noted later in this testimony, there was a slow-down in the project by laying off 15% of the workers on the Waterford 3 project due to financing problems in the 1977 period. Thus, just two years after initial construction started on the project, a financing problem occurred. Had the finance department been able to plan and project, based upon a detailed cost estimate, the Company would have known whether it could have financed this project on a timely basis. Beyond that, a reasonable detailed cost estimate would have provided the finance department guidance with regard to the timing and extent of financing needed in the 1977 period. Further, there was an additional financing problem in 1980. It is important to note that these cost estimates did not lead to avoiding these financing delays, but rather, possibly caused these financing delays. These factors must be taken into consideration when one is determining a quantifiable impact of imprudence.

In summary, it appears that TB&A has totally ignored the impact of the imprudent cost estimates of the Company and, as a matter of fact, is contradicting itself by relying upon the studies shown in Exhibit III-41 as well as not finding any imprudence with regard to the financing delays. These imprudent cost estimates found by TB&A and clearly shown in the data are quantifiable and did have a major impact on the cost of the Waterford 3 project. The quantification of this impact will be discussed later in my testimony when I discuss the financing delays.

SECTION VI

BUDGETING AND FINANCING-FINANCIAL MANAGEMENT

Q. DOES TB&A ADDRESS THE FINANCIAL MANAGEMENT OF THE WATERFORD 3 PROJECT IN ITS RETROSPECTIVE, REVIEW?

A. On a limited basis, TB&A addresses the financial management surrounding the Waterford 3 project. Considerable discussion in the TB&A report on this topic is devoted to the current financial status i.e., the position LP&L found itself in after the commercial operation of the Waterford 3 plant. At page III-46, TB&A notes the following:

> "LP&L's construction program dominated its planning and budgeting activities since the mid-1970's. The Waterford 3 project developed its own budgeting process, which resulted in a Waterford 3 budget and estimate that would be included in the construction budget. Based primarily on the level of Waterford 3 expenditures, the Waterford 3 project budget was not treated like those of other construction projects. Rather, the construction budget group, under the treasurer, accepted completed Waterford 3 budgets and estimates from the project management, and did not make Waterford 3 part of the interim prioritization process. The rationale behind this practice was that Waterford 3 was a needed generating facility and that the finance group lacked the necessary expertise to question such expenditures. While we would not expect the finance group to duplicate the project management group's expertise in estimating, TB&A

> does expect it to be aware of the aggressiveness of schedules and estimates and to plan accordingly." (Emphasis added)

TB&A is essentially stating that the finance group should have been aware of schedules as well as the true cost estimates for Waterford 3 so that it could plan and manage the financing of this major project. Not only were the schedules slips apparently not made known, but also the ultimate cost of the project was not even known. Therefore, financial management became impossible. At page III-47, TB&A notes the following:

> "In late 1977 LP&L reduced the number of construction workers employed on the Waterford 3 project by 15%, which the Company contended was due to inadequate rate relief. The project was 36% complete at the time."

Thus, just two years after the construction actually started on the Waterford 3 project, financing delays and problems were already occurring. This should have been a clear signal to LP&L management of the problems to come. TB&A also notes:

> "In May 1980 LP&L slowed construction activity on the facility. Anticipated delays in obtaining an operating license, along with financial difficulties, were sited as the reasons. The construction workforce was reduced from 3,000 to 2,000."

Once again, shortly after the previous financing delay other financing problems were still arising. The question of whether LP&L could truly

afford to finance this project relative to other alternatives should have been asked, but it appears to have been ignored. TB&A also notes:

> "Each of these delays was accompanied by fairly extensive cutback studies, which discussed and analyzed the options available to project management. Basically, the LP&L strategy represented an attempt to maintain the project's critical path schedule."

TB&A appears not to have examined the effect or impact of these cutbacks in the labor force, and the impact on direct cost of the project. Nor has TB&A addressed the issue of the poor cost estimates and its possible impact on the financing problems that occurred in 1977 and 1978, in terms of quantification of imprudence.

Q. DOES TB&A REACH ANY DEFINITIVE CONCLUSION WITH REGARD TO THE FINANCING OF THE WATERFORD 3 PROJECT?

A. At page III-51, TB&A concludes the following:

> "In the project finance area, LP&L reacted to financing difficulties adequately (for example, the 1985 cash crisis was dealt with adequately), but should have been more proactive in planning. The financial planners should have become more familiar with the factors driving Waterford 3 estimates and performed contingency planning based on the probability of increase in cost. They should also have calculated the consequences of the 1980 Waterford 3 project deferral studies on future LP&L revenue requirements, based on a proactive interaction with the Waterford 3 project."

First, with regard to LP&L reacting adequately to the 1985 cash crisis as mentioned by TB&A above, TB&A should have addressed the cash crisis which was occurring while construction was going on and not after commercial operation of the unit. In fact, during cross examination TB&A witnesses stated that they were not concerned nor was this retrospective review dealing with the time period after the commercial operation of Waterford 3. Thus, the TB&A analysis should have done more in-depth analysis of the 1977 and 1980 financing delays. Second, with regard to the 1980 Waterford 3 project deferral, TB&A believes that LP&L should have calculated the consequences of the impact of this deferral on future revenue requirements. It is obvious from this statement that TB&A, in fact, agrees that the deferral of the project in 1980 due to the financing has caused the cost of the Waterford 3 project to increase. Future revenue requirements will be higher due to the 1980 financial crisis and resulting slowdown on the construction of the project. Yet, TB&A does not take this into consideration, but rather one must assume that TB&A believes that LP&L ratepayers should pay higher revenue requirements because of poor planning on the part of LP&L. Lastly, at page III-51, TB&A states the following:

> "The lack of written budgeting policies, the absence of responsibility accounting, and occasional poor regulatory relations all represent management control problems. The presence of management control problems does not in itself cause cost escalations, although the risk of such escalations increases."

While TB&A believes the risk of these escalations may, in fact, be increasing, they do not address the problem of whether, in fact, cost escalations did increase. TB&A appears to have not made any attempt to determine whether the cost escalations occurred, resulting in higher revenue requirements for ratepayers on the Waterford project. This is particularly hard to understand given that TB&A was aware of the 14 cost estimate changes and the significant compounded cost increases over the duration of the project. Moreover, TB&A did not need to know that there were 14 cost estimate changes over the life of the project in order to realize that at almost any stage of the project the budgeting and finance management of LP&L was not acting appropriately, which was resulting in additional cost impact to the cost of Waterford 3.

SECTION VII

LICENSING

Q. HAVE YOU REVIEWED THE TB&A REPORT WITH REGARD TO LICENSING ISSUES FOR THE WATERFORD PROJECT?

A. Yes, I have. One of the major delays in the Waterford 3 project was the issuance of the construction permit (CP). LP&L applied for its CP in December 1970 and received the CP from the NRC on November 14, 1974. The granting of the CP to Waterford was well beyond the time period it took other utilities to get a CP for their nuclear plants announced in the same time frame as Waterford. For example, Exhibit ___ Schedule (DJL-4) shows the time frame it took in months for various utilities to receive their construction permit from NRC. As can be seen, the average time it took for most utilities was well below the 50-month period it took Waterford to receive its construction permit.

Q. WHAT WERE TB&A'S CONCLUSIONS REGARDING THE STAFFING FOR PURPOSES OF LICENSING?

A. At page IV-6 of the TB&A report, it is stated:

> "TB&A expects an adequate utility licensing organization to have a staff of sufficient size and experience to provide the interface between the NRC and the project and to provide a timely and cost effective interpretation of both existing and proposed regulations governing the project.
>
> LP&L took the lead with the AEC/NRC throughout the project. Although the LP&L staff was lean, and sometimes junior, it used contractors as necessary to provide both

depth and breadth. Based on a review of the number of staff and their combined experience, TB&A concludes that the licensing staffing was adequate. LP&L interpreted and communicated regulatory requirements to engineering and construction in a timely manner. Though LP&L utilized the expertise of outside contractors and consultants to interpret and meet regulatory requirements, overall responsibility remained with LP&L."

It appears that the LP&L's lean staffing required a reliance on Ebasco and Combustion Engineering to prepare most of the sections of the PSAR and ER. Ebasco and Combustion Engineering had responsibility for the technical content of these sections and similar responsibility for the technical content of responses to AEC requests for information. It should also be noted that the first round of questions from the AEC were submitted on June 29, 1971. Over the next year LP&L responded to approximately 400 AEC questions in 15 different PSAR amendments. TB&A noted that the responses were generally submitted within one or two months of the AEC questions. TB&A also notes at page IV-7 that errors in the seventh PSAR amendment prompted LP&L to admonish Ebasco to make the PSAR "letter perfect". LP&L requested Ebasco to provide a procedure outlining what Ebasco would do to review amendments.

Thus, it appears that errors on the part of the contractor, Ebasco, resulted in problems with dealing with the AEC.

Q. IS THERE OTHER EVIDENCE IN THE RECORD THAT WOULD INDICATE THAT LP&L MANAGEMENT HAD SUBSTANTIAL PROBLEMS WITH THE ACTIONS OF EBASCO BEFORE THE ATOMIC ENERGY COMMISSION CONCERNING LICENSING ISSUES?

A. Yes, there is. In a December 1973 memo to the file from a Mr. D. B. Lester of LP&L, it is stated that on the Waterford 3 project, Ebasco top management participation in major policy licensing and engineering matters has not been satisfactory. Further, it is stated:

> "Ebasco relations with the AEC staff has frequently been strained with the AEC feeling that Ebasco is often being unnecessarily difficult."

Therefore, the LP&L lean staff resulted in reliance on its architect-engineer for assistance in licensing of the project. But, Ebasco assistance led to strained relationships with the AEC over the licensing of this project. Clearly, this, in fact, may be one of the delays that caused the Waterford 3 not to get its CP in a period that extended over 50 months. It should be noted that the TB&A report does not indicate any evidence of the strained relationship between Ebasco and the AEC. Further, TB&A did not indicate whether or not the need for 400 questions and 15 PSAR adjustments were either reasonable and/or normal events. This lack of information pertaining to this area is puzzling when one considers that it generally took one or two months to respond to each series of questions associated with 15 PSAR amendments. It can only be assumed that TB&A did not even look into this factor with regard to the retrospective review.

TB&A refers to what it calls the second phase of the antitrust proceedings being initiated by the Department of Justice in and around August 1972 whereby petitions to intervene on antitrust matters were filed. As a result of the published notice, intervenors referred to as Cities, Dowell Chemical Company, Louisiana Municipal Association Utilities Group, and Louisiana Electric Cooperative Inc. filed petitions to intervene. The Cities were seeking access to the Waterford 3 unit and the use of LP&L's transmission lines for wheeling. It should be noted that the use of the LP&L transmission lines was a key matter of negotiation between the Department of Justice and LP&L. It was concluded by the early 1974 time period that the solution to these matters would be necessary for a final resolution to permanent license conditions on Waterford 3. The AEC staff provided a set of conditions which were agreed upon by all parties in February 1974. These license conditions provided the intervenors access to future nuclear units to be constructed by LP&L. Following that concession, LP&L announced two additional nuclear units which would be considered "future units" under that commitment in the license conditions. It should also be noted that LP&L also added a commitment to offer transmission service within certain limitations; LP&L had not previously made such a commitment.

In March 1974 LP&L announced the construction of the two St. Rosalie nuclear units which were, as referred to earlier, the future units committed to in the license conditions for LP&L's Waterford 3 unit. These units were to be available for participation by various intervenors in terms of ownership shares. Finally, on November 14, 1974, the CP was

issued to LP&L. The NRC later made certain changes to the CP; these changes were intended to clarify the conditions under which joint ownership in a nuclear plant must be offered to other entities by LP&L. The changes were incorporated as Amendment No. 1 to the CP on February 25, 1975.

It appears that LP&L went through a protracted negotiation with various intervenors concerning license conditions surrounding the construction of the Waterford 3 plant. It further appears that various intervenors wanted the right to buy into the nuclear unit as well as rights to the use of transmission facilities for wheeling purposes. LP&L ultimately conceded on these license conditions in many respects, and there is serious question as to whether the time spent in the antitrust litigation was well founded given the cost associated with the delay in the unit. Further, as noted above, LP&L found that the architect-engineer, Ebasco, participation in the CP resulted in strained relationships between the AEC and Ebasco. No determination was made by TB&A to determine whether the strained relationships resulted in the extension of the protracted litigation surrounding the procurement of the CP. Given the above and the fact that the average CP for a utility took approximately 40 months, it is my opinion that the unit was delayed by at least 10 months by the combination of Ebasco's strained relationship with the AEC which was unnecessary, and further, by LP&L's defensive antitrust position in which it ultimately gave into the intervenors concerning ownership shares and wheeling rights. Had LP&L pursued a philosophy of significant staffing with regard to the licensing of the project, the

licensing process may have been shortened by at least 10 months. The quantification of this 10-month delay is shown under the quantification section of my testimony.

Q. YOU STATED ABOVE THAT LP&L MADE CONCESSIONS AND PROVIDED THE INTERVENORS, SUCH AS THE MUNICIPALS AND COOPERATIVE SYSTEMS, ACCESS TO FUTURE NUCLEAR UNITS TO BE CONSTRUCTED BY LP&L. WERE THESE THE ST. ROSALIE UNITS THAT WERE ANNOUNCED ONE MONTH AFTER THESE CONCESSIONS WERE MADE WITH REGARD TO LICENSE CONDITIONS?

A. It appears that one month after LP&L made its concessions with regard to these license conditions it, in fact, announced the construction of the St. Rosalie project. These appear to be the future units which would be eligible for participation with regard to ownership shares. Also, as stated earlier, LP&L turned around and cancelled these units in its announcement made June 25, 1975. Thus, some 15 months after the initial announcement of these units, LP&L turned around and cancelled these same units that would be eligible for ownership rights by various intervenors. Also, as stated earlier, LP&L claims the reason for cancellation was an approximate doubling of the cost of these units from $1.2 billion to $2.3 billion, and the inability of LP&L to finance the higher costs was the principle reason for the action taken by LP&L. While there is no evidence to indicate that LP&L announced the decision to construct these units to satisfy the intervenors with regard to license conditions and the availability to buy into a future nuclear power unit, it is very unusual that no study was every done with regard to the economics of cancelling these units. Furthermore, if LP&L's position is correct that the

continuing construction of Waterford 3 was justified throughout the 1970's, then one would have to ask the question why these nuclear units were not picked up and built by some other entity on the MSU system given that the economics of nuclear were preferable to coal, gas or any other type of generation.

Also, it should be noted that TB&A accepted the concept that economic to-go analyses specific to Waterford No. 3 were not required since nuclear construction continuation could be implied by other studies. The cancellation of the St. Rosalie units would imply that either TB&A was wrong in its conclusion, or LP&L was playing a shell game with its antitrust intervenors.

SECTION VIII

STANDARDS FOR UNIT CANCELLATION

Q. DOES LP&L AND/OR MSU HAVE ANY STANDARDS OR GUIDELINES WHICH ARE FOLLOWED TO DETERMINE CONTINUED JUSTIFICATION, CANCELLATION, OR THE CONVERSION OF A PARTIALLY COMPLETED UNIT TO AN ALTERNATIVE FUEL SOURCE?

A. The Company has provided no record evidence that any studies are ever done with regard to the cancellation of projects. This is a very important issue with regard to the continued construction of Waterford 3 i.e., should the construction of Waterford 3 have gone on throughout the 1970's when it became apparent that Waterford 3 cost estimates were increasing at a rapid rate and its commercial operation schedules were being extended.

Jefferson Parish has sent a number of data requests to LP&L asking for the criteria and/or guidelines and/or studies related to the cancellation of specific units, in particular, Grand Gulf 2 and the St. Rosalie project. With regard to the Grand Gulf project, LP&L was asked for the current status of the nuclear generating station, a copy of all guidelines and assumptions made or established by LP&L or MSU for the Grand Gulf 2 task force which are to be utilized in the determination of whether to continue construction or cancel Grand Gulf 2. The Company was also asked to explain in detail the types of studies and investigations made or to be made before a determination will be made with respect to the continued construction or cancellation of Grand Gulf 2, and to provide a copy of those documents to Jefferson Parish so that it may, in effect, evaluate the types of guidelines and criteria LP&L or MSU relies upon in determining the continued economic justification of construction of any

project. In response to these data requests which are included in my testimony as Exhibit __ (Schedule DJL-5), the Company has stated:

> "LP&L objects to data request no. 8 for the reason that the status of Grand Gulf 2 is not a matter within the jurisdiction of the LPSC, and no element of LP&L's rate application is related in any way to Grand Gulf 2. Morever, LP&L has no authority over reports prepared by Middle South Utilities, Inc."

With regard to LP&L's response, it is apparent from these data requests that the Jefferson Parish is requesting the guidelines used and/or relied upon by LP&L and/or MSU with regard to cancellation. LP&L, in fact, refuses to provide such guidelines. Furthermore, LP&L states that it has no authority over reports prepared by MSU, but with regard to continuing economic justification studies, LP&L has, in fact, provided MSU reports on this matter where LP&L feels it benefits its position.

With regard to the St. Rosalie project, LP&L has provided no cancellation study that was used as a basis to cancel the St. Rosalie project. Further, LP&L uses the same argument that it has no authority over the MSU documents. Again, LP&L relied upon MSU documents to show that the continued construction of Waterford 3 was sound, yet when documents may question LP&L's decisions, they fail to provide them.

LP&L provided no basis for the cancellation of St. Rosalie other than a news release that was provided to the public on June 25, 1975. LP&L President E. A. Rodrique, in June 1975, stated that the doubling of the cost of construction of St. Rosalie from $1.2 billion to approximately

$2.3 billion, and the inability of LP&L to finance this higher cost, were the principle reasons for the actions taken i.e., cancellation. Beyond the news releases supplied by LP&L, no studies were ever provided with regard to the cancellation of St. Rosalie. The news release is contained in my Exhibit ____, Schedule (DJL-6). Further, TB&A indicated under cross-examination at the November hearings that they too asked for documents related to the St. Rosalie cancellation, and none were provided. TB&A found this to be unusual, however chose not to pursue the topic any further. As earlier discussed in this testimony, the decision to construct and then subsequently cancel the St. Rosalie units may, in fact, be tied to the licensing conditions on the Waterford unit rather than a doubling of the cost estimate.

In summary, LP&L and MSU either have no guidelines or bases which are regularly followed to determine when and if to cancel a project, or they absolutely refuse to provide such guidelines to this Commission. Clearly, such guidelines, assumptions, criteria and policies are very important when a system is building large units and making large investments. Any utility system must have some basis for determining the economics of the continued construction of an investment to protect ratepayers. One cannot continually rely on a mentality that all costs incurred can, in fact, be passed on to ratepayers whether they are economically viable investments or not. Clearly, companies must have guidelines and policies which protect not only their stockholders, but also, ultimately, the ratepayers i.e., the ultimate party that must pay all prudently incurred costs.

SECTION IX

OUTSIDE AUDITS OF THE WATERFORD 3 PROJECT FOR LP&L

Q. HAVE YOU REVIEWED THE AUDITS THAT WERE REQUESTED BY LP&L WITH REGARD TO THEIR WATERFORD 3 PROJECT?

A. Yes, I have reviewed some of the audits. The first such audit I have reviewed is what is referred to as the Management Analysis Company ("MAC") Audit for the Waterford 3 Project, dated September 21, 1977. LP&L's assignment to MAC was to provide an evaluation and audit of the Waterford 3 project including an assessment of the possibilities of the schedule being met and of staying within the cost estimate. Further, in performing the evaluation and audit, MAC was to identify problems which could critically impact the Waterford 3 project, and make a subjective analysis of the schedule and cost of the project.

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT MR. CAIN FELT LP&L WAS BEING UNFAIRLY CRITICIZED FOR ITS LEAN STAFFING PHILOSOPHY WITH REGARD TO THE WATERFORD 3 PROJECT. DID MAC ADDRESS THE ISSUE OF LEAN STAFFING IN ITS 1977 AUDIT OF THE WATERFORD 3 PROJECT?

A. Yes, it did, and MAC was very critical of the LP&L position with regard to staffing and its lean staffing philosophy. For example, at page 2 of the audit MAC concludes the following:

> "The long-held policy of Louisiana Power & Light has been to conduct their business related to engineering, construction, and operation of power plants by utilizing a very "lean" in-house organization with almost total reliance on the architect-engineer for engineering and

construction, and heavy use of consultants and outside service organizations during plant operations. This policy of "lean-ness" and almost total reliance on the A-E is, in MAC's opinion, one of the basic root causes of many of the problems associated with Waterford 3. (Emphasis added)

Further, at page 4 of the MAC report it is stated:

"Although the project organization is made up of extremely capable and dedicated individuals, it is too "lean" and functions in a rather unstructured manner making it almost impossible to perform effectively."

At page 5 of the MAC report under the heading of staffing, the conclusion is as follows:

"The existing LP&L project and site organization are lacking in numbers and in commercial nuclear plant experience necessary to effectively monitor and control the Waterford 3 project."

LP&L, in 1979, again hired MAC to do a construction monitoring audit on the Waterford 3 project. The 1979 MAC report, at page 1, indicates the following:

"LP&L is monitoring the construction of Waterford 3 nuclear project with four engineers and one technician. MAC is not aware of any other nuclear project in this country wherein construction is being monitored by few as owner individuals." (Emphasis added)

At page 2 of this audit, MAC states the following:

"In spite of these traits, these personnel cannot, in MAC's opinion, adequately cover those facets of construction monitoring that should be covered to ensure LP&L is receiving appropriate performance for the dollars being expended." (Emphasis added)

In summary, not only is the TB&A report critical of LP&L's philosophy of lean-ness with regard to construction monitoring of the Waterford 3 project, but LP&L's own consultants as far back as 1977 told the Company that its policy of lean-ness was inadequate. It appears that LP&L did not listen to its consultant's 1977 report, as I indicated above, the consultant's 1979 report continued to note that LP&L was deficient in its construction monitoring of the Waterford 3 project.

Q. IS MAC CRITICAL OF LP&L AND EBASCO IN OTHER AREAS WITH REGARD TO THE CONSTRUCTION OF THE WATERFORD 3 PROJECT?

A. Yes, MAC in both 1977 and 1979 was very critical of LP&L and Ebasco with regard to their participation in the Waterford 3 project. The basic thrust of both of MAC's 1977 and 1979 audits is that LP&L did not have sufficient staff and/or expertise to fully monitor the project and, in particular, Ebasco, the contractor. After the 1977 MAC report, LP&L then-president Wyatt wrote a letter to Ebasco indicating his concern with regard to the MAC findings.

Q. DID TB&A ADDRESS THESE AUDITS IN ITS OWN STUDY OF THE WATERFORD 3 PROJECT?

A. Yes, TB&A mentioned the studies, but it does not appear that TB&A reviewed the lean philosophy of LP&L with regard to staffing and, in particular,

its impacts on the costs associated with Waterford 3. At page III-20, TB&A states:

> "As far as owner-directed audits, TB&A felt that LP&L acted responsibly and in a timely manner by bringing in a third party auditor in 1977. This action was taken early in construction at a time when problems were beginning to surface. TB&A considered this one of the strongest examples of LP&L's control of Ebasco. However, LP&L did not respond in a timely manner to criticism of its own level of involvement and staffing." (Emphasis added)

While TB&A felt LP&L acted responsibly in getting management audits performed on the Waterford project, nonetheless TB&A did not find any imprudence or increased cost due to LP&L's lack of response to the points brought out in the audits. Further, TB&A found no quantifiable impact associated with such low staffing levels i.e., the lean staffing philosophy.

In the LILCO case with regard to the Shoreham project in which TB&A participated in the imprudence study with others, TB&A has alleged that they have found $1.5 billion of imprudence on that project because of factors which include the lack of project management. One of the findings of the New York Public Service Commission, RE Long Island Lighting Company, Case 27563, Opinion No. 85-23, dated November 16, 1985, was with regard to project management. At page 271 it is stated:

"the term, "project management," as it has been used in this proceeding, refers to fundamental, minimum requirements such as comprehensive and detailed planning for the project; creation of an organizational structure in which responsibilities of control and supervision are clearly defined and assigned; establishment of systems whereby information about schedule and budget problems can be transmitted promptly to the parties responsible for rectifying such difficulties; and assigning staff rationally so that each task may be entrusted to a reasonable number of suitably experienced personnel. We find that the project management is of critical importance for a construction project of the magnitude of Shoreham and that prudence required that LILCO make adequate and timely provisions for basic organizational requirements. The judges concluded that despite the obvious importance of effective project management as a prerequisite for orderly progress at Shoreham; "LILCO failed to develop a project plan adequate to oversee (Stone & Webster's) management of the project, to identify roles and responsibilities, to develop accurate and timely reporting systems which would enable it to monitor, measure, and control cost and scheduling, to adequately staff monitoring groups, or to adequately prepare for its accritical owner oversight rule."

It does not appear that TB&A truly challenged LP&L as to its owner oversight role with regard to Ebasco in the Waterford 3 project, while TB&A or others did challenge LILCO with regard to a similar issue. Furthermore, evidence shown in the MAC reports referred to earlier clearly indicates a substantial problem was occurring in 1977 and that problem had not been rectified by LP&L as can be seen in the second MAC study done in 1979. It appears that TB&A has made no effort to truly estimate and determine whether costs were excessive due to LP&L's limited oversight role. At page III-17 of the TB&A report, it is concluded:

> "From a top management perspective, TB&A was impressed by the level of involvement of LP&L's senior management. From the Board of Directors to the President to a Senior Officer and to a responsible Department Head, Waterford 3 was subject to a high level of scrutiny. This active participation by the upper management of LP&L was a key ingredient that made LP&L's lean staffing as effective as it was."

Furthermore, at page III-16 of the TB&A report, it is stated:

> "It was not a routine practice to present a formal project status report to the Board during this time frame. Although not recorded in the minutes, past LP&L presidents Mr. Rodrique and Mr. Wyatt recall during TB&A interviews that on numerous occasions they gave the Board informal updates on Waterford 3 status. Beginning in September 1980, LP&L senior management initiated such a practice.

From 1980 through commercial operation in 1985, the Board was given a formal status report on Waterford 3 at nearly every meeting. These reports were essentially a condensed version of the monthly status report prepared by Ebasco and LP&L."

It is very interesting to see that TB&A concluded that such reports were provided to the Board of Directors when, during Mr. Cain's testimony of November 19, 1986, Mr. Cain indicated that he was not aware of any such studies or reports being provided to the Board. In particular, at page 263 of the transcripts, Mr. Cain is asked the question:

Question:

"Was there ever a study of the prudence and the feasibility of going forward with Waterford 3 at any time during the construction path of the facility that approached the study in terms of breadth and expense?

Answer:

I don't know, sir, whether or not any such (inaudible coughing) was ever conducted in the past that approached the scope an breadth of the Theodore Barry study."

Furthermore, when Mr. Cain was asked about the costs associated with the construction project, for example, at page 264 of the transcripts:

Question:

"Do you know what the sunk costs were at any point along the line of the construction of this project?

Answer:

From 1983 on."

At page 265 of the transcripts, Mr. Cain states:

"I've already shared with you where my curiosity started which was 1983. Now, if you want to infer something else, go ahead and infer it and on what basis."

And also at page 266 of the transcripts, Mr. Cain was asked the question:

Question:

"OK, going beyond the original decision, what about any second looks at the feasibility of constructing Waterford 3 throughout the construction process?

Answer:

I'm only competent to testify to what happened after 1983 and there were no such studies done after 1983."

These excerpts from the cross-examination of LP&L President Cain are very interesting. Mr. Cain appears to be taking the position that he only knew about Waterford 3 from 1983 forward, and 1983 is the date at which Mr. Cain became president of LP&L. But, as I noted earlier, TB&A concludes that top management from the Board of Directors on down were kept well informed and involved in the Waterford 3 project. The interesting point to note is that one of the Board of Directors of LP&L from 1978 until the present was, in fact, Mr. James Cain. Therefore, if Mr. Cain who has testified under oath claims he knows nothing about the Waterford 3 project details from the period 1978 to 1983 when he was, in fact, one of the Board of Directors of LP&L, it is difficult to infer how

the Board of Directors knew what was going on at the Waterford 3 project. Either Mr. Cain is supplying false information to this Commission, or Mr. Cain never attended Board meetings nor picked up Board minutes in the period 1978 to 1983. Or lastly, the Board of Directors were, in fact, not kept informed of the Waterford 3 project. Therefore, TB&A's conclusion that the Board i.e., top management of LP&L, was informed and on top of the decisions surrounding the Waterford 3 project and its continued construction may be somewhat erroneous.

In summary, not only did LP&L have a lean oversight role with regard to staff, but also there is evidence that top management which TB&A relies upon for effective oversight was not overseeing the project. Clearly, TB&A's conclusion that:

> "this active participation by the upper management of LP&L was a key ingredient that made LP&L's lean staffing as effective as it was."

is subject to a great amount of doubt when one examines the participation of the Board of Directors. It would appear that the possibility exists that there was, in fact, no true oversight as the MAC report indicates, and TB&A's conclusions are invalid, and further, there may, in fact, be cost increases due to this imprudence on the part of LP&L. At this time, I have no way of documenting the cost increases that may, in fact, have occurred due to LP&L's lack of oversight, and it would be my suggestion that this Commission review this issue prior to making a final decision on the Waterford 3 prudence.

SECTION X

QUANTIFICATION OF IMPRUDENCE

Q. DO YOU HAVE ANY COMMENTS WITH REGARD TO TB&A'S CALCULATION OF THE QUANTIFICATION OF IMPRUDENCE?

A. Yes, I have a number of comments with regard to TB&A's approach to the quantification of imprudence. First, with regard to TB&A's approach i.e., the AFUDC method, I believe that such a method leaves some costs unquantified. Also, if the AFUDC method employed by TB&A in its retrospective review is to be relied upon, one must capture all the costs so as to make the approach reasonable.

Q. WHY DO YOU BELIEVE THE AFUDC METHOD EMPLOYED BY TB&A IS NOT AN EXACT METHOD?

A. TB&A itself admits the the AFUDC method it employed is not an exact method. For example, at page VIII-8, TB&A states the following:

> "The AFUDC method is an approximate method. In order to perform a more rigorous and accurate calculation, significant additional detail would be required. After a specific delay in the project's critical path were identified, every task performed after the beginning of each delay would have to be analyzed to determine if it was delayed and whether or not it was on the critical path. Then, for each task that was delayed as a result of each critical path delay, the amount of the delay, the initial AFUDC savings, the escalation, and the additional AFUDC costs would have to be determined. The identification of

all tasks and the collection of data for each of the tasks represents a substantial effort. In many cases, the data does not exist and would have to be estimated. TB&A believes that this detailed a calculation is neither reasonable nor necessary and that the AFUDC is an adequate approximation."

Clearly, TB&A would agree that the approach is an approximation, but TB&A has left out a major cost factor in its analysis which has a direct impact on a delay in the start-up of a nuclear power plant. The item that TB&A totally left out of its calculation is the fuel cost savings associated with a nuclear power plant. If, for example, a nuclear power plant is delayed by, say, six months, then ratepayers must pay higher fuel costs for an additional six months. Thus, if the project is delayed due to imprudence on the part of LP&L, then why does TB&A believe that ratepayers should bear the additional and higher fuel costs associated with alternatives other than the cheaper nuclear energy?

It is my opinion that TB&A inadvertantly left out the fuel savings, and such fuel savings should be added into any delay cost calculation.

It should be pointed out that I have used the TB&A approach to the calculation of delay in quantifying my delay adjustments contained in the next section of my testimony. I have also included the fuel cost savings which must be added to the AFUDC cost associated with a delay.

SECTION XI

QUANTIFICATION OF PROJECT DELAYS

Q. BASED ON YOUR REVIEW OF TB&A AND OTHER DATA, WHAT HAVE YOU CONCLUDED?

A. My review of TB&A's report and other data has led me to conclude the findings in TB&A's report are flawed and significantly understate the overall project delay.

Further, I have concluded that a great deal of additional investigation into various areas of the Waterford 3 construction project is warranted. As stated earlier, TB&A made a limited investigation given the constraints of its underlying assumptions and guidelines.

My first recommendation is that the LPSC send TB&A back to the "drawing board" to complete the assignment it was originally contracted to perform. The TB&A report can by no means be characterized as a full-fledged prudence review. As is shown in the direct testiony of Mr. Pous, an additional investigation with regard to continuing justification of this project is necessary to ensure that LP&L ratepayers are not charged for imprudently incurred costs.

Q. HAVE YOU BEEN ABLE TO QUANTIFY ANY ADDITIONAL IMPRUDENCE BEYOND TB&A'S $143 MILLION ESTIMATE?

A. Yes. Based on my analysis, considering time and data constraints, I have calculated additional dollars associated with project delays due to LP&L's actions. These calculations are based on the TB&A data, as well as data responses and other industry material.

These quantifications are based on: delays due to financing, delays due to antitrust litigation, and further review of the TB&A calculation of the 163-day delay.

Q. PLEASE EXPLAIN THE FINANCING DELAY.

A. Based on my earlier testimony, data responses, it is my opinion that an absolute minimum of a one-month penalty should be assigned to the 1977 and 1980 construction delays due to financing problems. While there are numerous other cost increases associated with these financing delays, the total two-month penalty is a conservative estimate.

Q. PLEASE EXPLAIN THE QUANTIFIED TEN-MONTH DELAY ASSOCIATED WITH THE ANTITRUST LITIGATION.

A. As I stated earlier in the licensing section of my testimony, the Waterford 3 CP took approximately ten months longer than other nuclear units that applied for a CP at the same time as LP&L applied.

In addition, the situation might have been worsened by the strained relationship between Ebasco and the AEC/NRC. Furthermore, LP&L took a hard-line stance with intervenors in the antitrust litigation, only to ultimately concede in the final license conditions after a protracted litigation.

Q. PLEASE EXPLAIN YOUR ANALYSIS WITH REGARD TO TB&A'S QUANTIFICATION OF A 163-DAY DELAY.

A. Based on a review of the TB&A report and the bases supplied by TB&A with regard to the 5-1/2 month delay employed in its report, it is my opinion that TB&A's calculation is woefully inadequate. At page VII-7 of the TB&A report, it is stated:

"LP&L project control staffing was inadequate prior to 1978. This contributed to the late development of detailed start-up schedules. TB&A concludes that these four deficiencies resulted in a delay on the order of two months. TB&A also found that the LP&L start-up organization was not adequate until 1982. In addition, the late hiring of a strong, experienced plant manager left the LP&L organization without adequate capability to reasonably perform the final start-up activities. TB&A concludes that these two deficiencies resulted in a delay of three to six months."

At page VIII-7, TB&A states the following with regard to the piping contract:

"Any additional preparation time and piping work that could have been done early would have reduced the pipe fitter craft manpower shortages that occurred from 1978 on and allowed more concentrated effort on the critical path activities then. TB&A therefore concludes that the four-month delay in awarding the piping contract resulted in approximately a one-month overall project delay."

TB&A combined the effects or impacts of the two delays referred to above and concluded, at page VIII-7, the following:

"TB&A therefore finds that these six deficiencies, combined with the delay in awarding the piping contract discussed

earlier, combined to cause an impact on the order of a delay of six to nine months."

Actually, the range or time period that TB&A should have looked at was a range of six to twelve months, given that the piping contract delay was anywhere from one to four months. TB&A apparently chose the lower end of this range of six months based upon the date of publication of the Gambit article in May 1983. TB&A ignores the fact that the May 1983 Gambit article may have been written even earlier had LP&L been prepared to load fuel earlier. Furthermore, intervenors' allegations may have been raised earlier if fuel had been ready to load earlier, with or without the Gambit article being published. Thus, TB&A's choice of the lower end of the range, based upon the publication date of the Gambit article, is not appropriate, and to assume intervenor allegations would not have been raised had fuel been ready to load earlier is not appropriate.

Given the above, it is my opinion that the upper end of the range can reasonably be selected. It is the fuel load date, and not the Gambit article, that would have triggered intervenor allegations. Therefore, there is no basis to believe that the upper end of the range of approximately one year, as I have calculated, is not more appropriate in this case. Therefore, I have concluded that the one-year delay associated with the findings of the TB&A analysis is more realistic than the 5-1/2 months employed by TB&A.

Q. PLEASE QUANTIFY YOUR 24-MONTH DELAY FINDINGS.

A. The 24-month delay findings that I have described above and throughout my testimony results in an imprudence calculation or finding of

$741,410,000. This calculation is based upon the AFUDC method employed by TB&A in its analysis. The difference between my analysis and the TB&A analysis is that I have included the impact of foregone fuel savings associated with the delay in the nuclear power project. The calculation of my estimate of imprudence can be found in Exhibit _____, Schedule (DJL-10).

SECTION XII

COST OF SERVICE AND LP&L RATE REQUESTS

Q. EARLIER IN YOUR TESTIMONY YOU STATED THAT THE LP&L RATE REQUEST IS SOMEWHAT UNCLEAR. PLEASE EXPLAIN THAT STATEMENT.

A. As stated earlier the increase requested by LP&L in this case is, to say the least, very unclear for a number of reasons. As noted earlier, the Company filed for $444,000,000 in rate relief in September 1985. Also as noted earlier, the LPSC staff increased the revenue requirement to $467,000,000 in the November 14, 1985, LPSC Order No. U-16945. Lastly, the Company in statements during cross-examination has indicated the need for an additional $72 million per annum based upon updating the test year through December 1985.

Given the above facts, and also noting that I am now aware of any amendments to the filing, it is unclear what the true rate request is in this case. For my analysis I am assuming that LP&L is requesting the following: a) the $215 million already granted by the LPSC in interim rate relief, b) $206 million deferred in the LPSC Order No. U-16945, and c) the $72 million referred to during the Company's cross-examination and its updated cost of service. Thus, based on the above facts, it would appear that the Company's September, 1985, rate request is now $493 million rather than the $444 million originally requested. This $493 million rate request will be the basis for my analysis in the cost of service section of my testimony.

It should be further noted that I do not agree that the Company should be able to increase its rate request during a proceeding without

either amending its filing for such a request or, furthermore, notifying ratepayers of the changed request. It is also my understanding that counsel for Jefferson Parish has filed a motion to dismiss the additional $72 million rate request associated with the updated test year.

SECTION XIII

NEW TAX LAW

Q. HAS LP&L MADE A COST OF SERVICE ADJUSTMENT IN ITS UPDATED COST OF SERVICE FOR THE IMPACTS OF THE NEW TAX LAW?

A. Yes, LP&L has made some adjustments in its updated cost of service to reflect the impacts of the new tax law. I should point out that the adjustments made by LP&L are not complete.

Q. WHAT ADJUSTMENTS HAS LP&L MADE WITH REGARD TO THE NEW TAX LAW?

A. In its updated COS, LP&L has reduced Federal Income Taxes ("FIT") payable by approximately $12.6 million. LP&L has also made an adjustment to deferred income taxes by reducing these taxes in the COS by approximately $1.3 million.

The basis for both of these reductions is stated in the notes to the updated COS, where LP&L indicates, in its notes for column 31, the following:

> "This adjustment assumes the Congress will vote for a proposed change in the federal statutory corporate income tax rate from 46% to 34% effective 7/1/87. No other provisions to the proposed change have been assumed. In addition, this adjustment reverses the 1985 tax loss carryforward from a deferred federal income tax item to a federal income tax item."

The first problem with LP&L's income tax adjustment is that this tax change is only reflected in rates for six months. Given that the lower incremental corporate tax rate of 34% becomes effective on July 1, 1987,

LP&L reflected six months at 46% and six months at 34%. The effective blended rate employed by LP&L as reflected in the updated COS is a 40% rate. LP&L has not provided a mechanism to reduce rates in the future which would take into account a full year of the lower tax rate.

I find LP&L's failure to provide such a mechanism somewhat one-sided given the fact that LP&L is supporting a staff proposal to collect deferred costs through future rate adjustments. While LP&L is willing to support future automatic rate adjustments to collect increased amounts from ratepayers, they have not proposed future adjustments with respect to taxes to ensure that LP&L does not over-collect from ratepayers. Based on the LP&L calculations in the updated COS, LP&L will over-collect from ratepayers approximately $14 million per year beginning January 1988. It would be my recommendation that the LPSC order LP&L to have a mechanism in place so as to automatically adjust rates to reflect a full year's impact of the new tax law after January 1, 1988.

Q. ARE THERE OTHER ADJUSTMENTS THAT MUST BE MADE TO REFLECT THE IMPACTS OF THE NEW TAX LAW?

A. Yes, there are. The Company has failed to adjust for the impacts associated with excess deferred taxes. The Company has not made an adjustment for the flowback of these excess amounts to ratepayers. During cross-examination of LP&L witness McLetchie, he indicated that the Company had not had the time or the data to calculate this adjustment.

Q. PLEASE EXPLAIN THE CONCEPT OF EXCESS DEFERRED TAXES.

A. In ratemaking under tax normalization rules there exists a timing difference between the size of tax deduction (expense) for book purposes and tax purposes. The best example of such a timing difference is with regard to depreciation expense. For tax purposes, a utility will use the depreciation expense under an accelerated depreciation schedule i.e., a higher depreciation expense, while for book purposes the same utility will use straight line depreciation expense. Given the above example, this Company now has more deductions (expense) for tax purposes than for book purposes. The difference between the two tax payments is referred to as deferred taxes.

Deferred taxes are paid by ratepayers in the COS. The Company is allowed to keep these deferred taxes or cash flow until it must pay this future tax obligation to the U. S. Treasury. In other words, at some point the accelerated depreciation expense will be lower than book depreciation expense, and the deferred taxes will turn around.

These deferred taxes (accounts 281-283), while being held by the Company, are used to offset i.e., lower rate base. Thus, ratepayers are not providing a return on these funds since they have provided this cash flow at a time period prior to when the Company will have to spend such funds.

Q. DID LP&L COLLECT THESE DEFERRED TAXES ASSUMING A 46% TAX LIABILITY IN THE FUTURE?

A. Yes, they did. Under the new tax law, LP&L will have a 34% tax liability rather than a 46% liability associated with these deferred taxes. Thus, LP&L has an excess quantity of ratepayer funds in the form of deferred

taxes i.e., the difference between deferred taxes collected at a 46% rate versus a 34% rate.

Q. HAVE YOU CALCULATED AND ADJUSTMENT TO THE COS THAT REFLECTS AN ADJUSTMENT FOR THESE EXCESS DEFERRED TAXES?

A. Yes, I have. Under the new tax law, these excess deferred taxes are to be flowed back to the ratepayers ratably i.e., over the life of the assets which created these deferred taxes. (See Exhibit ____ Schedule DJL-7).

Exhibit ___ Schedule (DJL-7) is an approximation of the impact of adjusting for these excess deferred taxes. As can be seen from Exhibit ___ Schedule (DJL-7), the annual impact would be a reduction to COS of approximately $1.8 million.

In summary, the tax law change requires a twofold adjustment as described above, the annual impact of these adjustments based on the updated COS, is approximately $14,800,000 ($12.6 million + $1.3 million + $.9 million) during 1987, and approximately $29,600,000 ($12.6 million + $1.3 million + $1.8 million + $13.9 million) during 1988 and thereafter.

Q. WHAT OTHER COST OF SERVICE ADJUSTMENTS ARE YOU PROPOSING BE MADE TO THE LP&L UPDATED COST OF SERVICE?

A. An additional COS adjustment that I would propose be made is with regard to column 22 of the udated COS. (The updated COS is contained in Exhibit ___, Schedule DJL-8.) Column 22 represents amounts that LP&L is proposing to expense to ratepayers for storm damage reserves.

LP&L, at page 3 of 4 of its updated cost of service in column 22, is proposing to charge ratepayers approximately $3.4 million per year to

accrue in a fund for storm damage reserves and injuries and damages reserves.

Q. WHAT LEVEL OF RESERVE FOR STORM DAMAGES DOES THE COMPANY CURRENTLY HAVE?

A. It is my understanding that the Company has a storm and injury damage reserve of approximately $6 million as of September 1986.

Q. WHAT LEVEL OF STORM DAMAGES HAS THE COMPANY INCURRED SINCE 1982?

A. It is my understanding that the Company has incurred the following amounts of storm damages to its system:

1982: $2,206,000

1983: $2,576,000

1984: $1,187,000

1985: $1,153,000

It would appear from the above that the Company has approximately three times the amount in a storm damage reserve as it has incurred in any of the past three years with regard to storm damages. Thus, it would be my recommendation that this Commission not allow the Company to accrue any more dollars for its storm damage reserve, and consider the current reserve of some $6 million as sufficient. This is especially important at a time when rates are increasing substantially due to the addition of the Waterford 3 nuclear station to rate base.

I would also point out, that with regard to the $6 million storm damage reserve, the Company apparently is not including a rate base offset for those funds. In other words, ratepayers supply the funds as an insurance policy for the Company in case storm damage occurs. Thus, the Company has customer-contributed capital for which it is not giving the

benefit of a rate base reduction to ratepayers. Therefore, a second adjustment entailing a rate base reduction of $6 million is warranted for the storm damage reserve.

Q. WHAT IMPACT WILL YOUR PROPOSED ADJUSTMENTS HAVE ON COST OF SERVICE?

A. The impact of eliminating the annual reserve payment results in a reduction to revenue requirements of approximately $3.4 million. The second adjustment is to reduce the return by eliminating $6 million from rate base. The impact of this rate base reduction on revenue requirements is approximately $1.2 million. Therefore, the total impact of this proposed adjustment on revenue requirements is approximately $4.6 million.

Q. ARE THERE ANY OTHER COST OF SERVICE ADJUSTMENTS THAT YOU WOULD PROPOSE THIS COMMISSION TO CONSIDER WITH REGARD TO THE UPDATED COST OF SERVICE OF LP&L?

A. Yes, there are. With regard to the updated cost of service, at page 3 of 4, column 21, the Company is proposing to include a write-down of a cancelled coal plant. In its footnotes supporting this adjustment, LP&L states the following:

> "In December 1985, the Company recorded a write-down of the Company's share of certain costs applicable to the Middle South System's indefinitely delayed future fossil generating facilities totalling approximately $44.4 million. For ratemaking purposes, the Company is requesting recovery of this write-down over a 10-year period, and the unamortized balance be included in the rate base."

It is the unamortized portion being included in rate base that I differ with the Company on in this issue. Should this Commission decide to allow LP&L to write off the delayed coal project, there should be some consideration of sharing this burden between ratepayer and stockholder. While the Company stockholders receive a higher return on their equity because of risks associated with that return, ratepayers should not be expected to bear the full brunt of various investments that are determined to be uneconomical or imprudent. Therefore, it would be my recommendation that if the LPSC accepts LP&L's proposal to write off this plant over ten years, that the unamortized portion not be included in rate base. In this way, LP&L will cover its full investment in this project, but it will not be allowed to earn a return on the unamortized balance from ratepayers. Clearly, the used and useful concept with regard to utility regulation is applicable in this situation. The plant is not used nor useful, but the ratepayers are providing the Company its entire investment in this project back to the Company.

Q. WHAT IMPACT WILL THIS HAVE ON THE COS AS PROPOSED BY LP&L?

A. The impact of reducing rate base for the standard coal plant of $40,683,853 is approximately $8,000,000 on cost of service.

SECTION XIV

INTERIM RATE RELIEF

Q. DO YOU HAVE ANY COMMENTS WITH REGARD TO THE LPSC NOVEMBER 14, 1985 ORDER U-16945 GRANTING LP&L INTERIM RATE RELIEF?

A. Yes, I do. It appears that LPSC in Order U-16945 granted too much relief due to an incorrect calculation of revenue requirements.

Q. HOW DID THE LPSC CALCULATE THE QUANTITY OF INTERIM RATE RELIEF AND DEFERRED REVENUES?

A. Exhibit ____ Schedule (DJL-1) contains the LPSC staff data response to a Jefferson Parish data request concerning interim rate relief.

As can be seen from Table A of Exhibit ____ Schedule (DJL-9), $215 million of current revenue and $206 million of deferred revenue was granted by the LPSC.

Q. DO YOU AGREE THAT $206 MILLION OF DEFERRED REVENUE REQUIREMENTS IS APPROPRIATE GIVEN THE CALCULATION ON TABLE A?

A. No, I do not. This calculation fails to take into consideration the impact of deferred taxes associated with the $206 million expense deferral.

Q. WHAT WOULD BE THE IMPACT ON THE DEFERRAL IF THE COMMISSION HAD TAKEN INTO CONSIDERATION DEFERRED TAXES IN THE DEFERRAL OF EXPENSES?

A. I have made this calculation and it is shown in Exhibit ____ Schedule (DJL-9). As can be seen, the true revenue requirement deferral is $187 million and not $206 million. Thus, it would be my recommendation that this Commission take this factor into consideration in its decision on this docket. To ignore the impact of deferred taxes on this issue would result in overcharing ratepayers approximately $18.3 million per year.

SECTION XV

SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH REGARD TO THE TB&A REPORT (PRUDENCE ISSUE) AND THE OTHER COST OF SERVICE ITEMS DISCUSSED IN YOUR TESTIMONY, AS WELL AS THE TESTIMONY OF MR. POUS.

A. Starting with the testimony concerning the TB&A report, it is my recommendation that the LPSC send TB&A back for further and more in-depth investigation into the Waterford 3 prudence issue. This Commission is correct in demanding a full-fledged prudence review so as to assure ratepayers that every penny expended on the Waterford 3 project was prudently spent.

A second alternative, (if the LPSC does not require some additional investigation into the Waterford 3 project, especially with regard to the continuing justification issue), is to rely on the Charles Komanoff generic study discussed in the testimony of Mr. Pous. This would result in an imprudence finding of $802,825,000.

A third alternative would be to base imprudence disallowances on my testimony. The testimony addresses the TB&A report directly and, based on my review of the TB&A report as well as the data supplied by LP&L, it would appear that a 24 month imprudence delay in Waterford 3 construction project, rather than TB&A's estimated 5-1/2 month imprudence delay can be estimated. Further, using TB&A's own assumptions and approaches, an imprudence finding of $741.4 million relative to Waterford 3 can be quantified, rather than the TB&A estimate of $143,000,000.

The final option, which I have not addressed in my testimony, is for the Commission to simply maintain the previously established level of $284,000,000 of disallowed cost of the Waterford 3 project. However, based on the information contained in Mr. Pous' and my own testimony, I cannot recommend this alternative.

Thus, the Commission has four options with regard to prudence;

(A) Send TB&A back to work with regard to a least cost life cycle analysis, so as to determine continued economic justification of Waterford 3, as well as an investigation into other issues raised in my testimony.

(B) Rely on the generic results of the Charles Komanoff Grand Gulf 1 least cost life cycle analysis - the result being a $802,825,000 imprudence finding.

(C) Adjust the TB&A findings to correct the errors and oversights of TB&A, as shown in my testimony - the result being a $741.4 million imprudence finding.

(D) Accept the TB&A report and maintain the $284 million imprudence adjustment agreed to by LP&L in Order No. U-16945. (An option which I do not believe can be supported by the evidence in this record.)

Q. WHAT IS THE IMPACT ON THE PROPOSED LP&L RATE REQUEST OF YOUR PROPOSED ADJUSTMENTS?

A. The impacts of the recommendations made by Mr. Pous and myself can be seen in the following table:

Proposed Revenue Requirement Adjustments

Line No.	Description	Revenue Requirement Impact Amount (000's)
(1)	Prudence Adjustment	(109,600)
(2)	Depreciation Expense	(2,784)
(3)	Rate Base Offset Storm Damage	(1,182)
(4)	Expense Storm Damage	(3,377)
(5)	Excess Deferred Taxes	(1,777)
(6)	Settlement Adjustment Deferred Taxes	(18,668)
(7)	New Tax Law Adjustment	(13,500)
(8)	Standard Coal Plant Adjustment	(8,015)

Thus, although we have not performed a complete COS analysis due to time constraints, the revenue requirements requested by the Company should be reduced significantly. Moreover, the imprudence adjustement has been quantified without the interrelated adjustments which I have proposed, nor do the other cost of service issues reflect the appropriate adjustment to items such as: return on equity; cash working capital; decommissioning; materials and supplies; as well as other accounting and financial costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX I

Q. BRIEFLY DESCRIBE YOUR EXPERIENCE.

A. After completing my graduate work at Tufts University, I was employed by Doane College, in Crete, Nebraska, where I taught in the Economics Department. I have taught economics, statistics, econometrics, business, and computer science courses. Since leaving academia, I have been continuously employed in various phases of utility regulation.

Q. WHAT IS YOUR EXPERIENCE IN PUBLIC UTILITY REGULATION?

A. As a Rate Analyst and Senior Statistical Analyst with the Department of Public Service of Minnesota, I was involved in various phases of utility regulation. Some of the projects in which I was involved include electric, gas, and telephone rate design; cost of service analyses; and cost of capital analyses. I also developed software systems, data bases, and management systems for cost of service analyses.

Q. PLEASE OUTLINE YOUR EXPERIENCE WITH R. W. BECK AND ASSOCIATES.

A. I was employed by R. W. Beck and Associates from 1982 through 1986. My work primarily involved utility regulation. The major areas in which I worked were forecasting, econometric model building, general cost of service analyses, cost allocation studies, and cost of capital studies. I have submitted testimony on many cost of service issues before the State and Local Regulatory Commissions of Minnesota, North Carolina, South Carolina, Louisiana, Texas, Nebraska, and the Federal Energy Regulatory Commission. A list of the cases and jurisdictions in which I have filed testimony is contained in this Appendix I.

Q. WHAT TYPE OF FIRM IS DIVERSIFIED UTILITY CONSULTANTS, INC.?

A. Diversified Utility Consultants, Inc., is a consulting firm whose clients are primarily involved in utility rate regulation.

APPENDIX I (CONTINUED)

FEDERAL ENERGY REGULATORY COMMISSION:		
Southern California Edison.....	ER82-427-000	Forecasting
Alabama Power Company.....	ER83-369-000	Cost of Capital
Florida Power & Light.....	EL83-24-000	Cost Allocation/ Rate Design
Arizona Public Service Company.	ER84-450-000	Cost of Capital
Florida Power & Light.....	ER84-379-000	Cost of Capital/Rate Design/Cost of Service
LOUISIANA PUBLIC SERVICE COMMISSION:		
Louisiana Power & Light.....	U-15684	Cost of Capital/ Depreciation
Louisiana Power & Light.....	U-16518	Interim Rate Relief
MINNESOTA PUBLIC UTILITIES COMMISSION:		
Northern States Power.....	G002/GR-80-556	Statistical/Forecasting
Northwestern Bell.....	P421/GR-80-911	Rate Design/Forecasting
Norman County Telephone.....	P420/GR-81-230	Rate Design/ Cost of Capital
Montana Dakota Utilities.....	G009/GR-81-448	Financial/Cost of Capital
New ULM Telephone Company.....	P419/GR-81-767	Financial
Interstate Power Company.....	E001/GR-81-345	Financial
Continental Telephone.....	P407/GR-81-700	Cost of Capital
NORTH CAROLINA UTILITIES COMMISSION:		
North Carolina Natural Gas..... Corporation	G-21, Sub 235	Forecasting/ Cost of Capital/ Cost of Service
PUBLIC SERVICE COMMISSION OF INDIANA:		
Kokomo Gas & Fuel Company	38069	Cost of Capital

APPENDIX I (CONTINUED)

PUBLIC UTILITIES COMMISSION OF TEXAS:		
Southwestern Electric Power....	4628	Rate Design/Financial/ Forecasting
Southwestern Electric Power....	5301	Cost of Service
Gulf States Utilities Company..	5560	Cost of Service
Gulf States Utilities Company..	6525	Cost of Capital/ Financial Integrity
Central Power and Light	6375	Cost of Capital/ Financial Integrity
SOUTH CAROLINA PUBLIC SERVICE COMMISSION:		
Piedmont Municipal Power..... Agency	82-352-E	Forecasting
TEXAS RAILROAD COMMISSION:		
Energas Company.....	5793	Cost of Capital
Westar Transmission Company....	4892/5168	Cost of Capital/ Cost of Service
Westar Transmission Company....	5787	
SCOTTSBLUFF, NEBRASKA CITY COUNCIL:		
K. N. Energy, Inc.....		Rate of Return
CITY COUNCIL OF THE CITY OF HOUSTON, TEXAS:		
Houston Lighting and Power Company		Forecasting

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. U-16945

LOUISIANA POWER & LIGHT COMPANY

EXHIBITS

OF

DANIEL J. LAWTON

DIVERSIFIED UTILITY CONSULTANTS, INC.

ON BEHALF OF

JEFFERSON PARISH

December 1986

EXHIBIT ____

Schedule (DJL-1)

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

Nov. 14 ORDER NO. U-16945

Louisiana Power & Light Co., ex parte Docket No. U-16945

In re: Application for an interim increase in retail electric rates

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This case involves the application of Louisiana Power & Light Co. ("LP&L") for an emergency increase in its rates and charges for retail electric service in Louisiana. LP&L is a wholly owned subsidiary of Middle South Utilities, Inc. ("MSU"). LP&L and three other operating company subsidiaries of MSU, New Orleans Public Service, Inc. ("NOPSI"), Arkansas Power & Light Co. ("AP&L") and Mississippi Power & Light Co. ("MP&L"), form a highly integrated electric system serving customers in Louisiana, Arkansas, Missouri and Mississippi. A separate generating subsidiary of MSU, Middle South Energy, Inc. ("MSE"), owns the Grand Gulf No. 1 nuclear generating station, which recently went into commercial operation and began supplying electricity to the four MSU operating companies under rate schedules approved by the Federal Energy Regulatory Commission.

Under the decision of the FERC in Middle South Energy, Inc., Docket No. ER82-616-000 and Middle South Services,

Inc., Docket No. ER82-483-000, Opinion No. 234 (FERC, 1985) LP&L was allocated a 14% share of the power, energy and costs associated with Grand Gulf No. 1. The decision of the FERC, as to the allocation issue, was based on the proposal originally made to the FERC by this Commission in Docket No. 82-616-000 and adopted by Presiding Administrative Law Judge Ernst Liebman as a recommendation to the FERC. Subsequently, in Docket No. ER82-483-000, another presiding administrative law judge recommended an allocation of approximately 42% of Grand Gulf No. 1 to LP&L. The resolution of the allocation issue by the FERC significantly reduced the LP&L share of Grand Gulf No. 1 and the cost of the unit to LP&L ratepayers. The first year base rate cost of the jurisdictional portion of the 14% allocation to LP&L is approximately $113.9 million.

In October, 1985, the Nineteenth Judicial District Court ("district court") ordered that LP&L be permitted to implement a rate increase for Grand Gulf of $113.9 million. Louisiana Power & Light Co. v. Louisiana Public Service Commission, et al., No. 292-026 (19th J.D.C.). This order has been appealed. After fuel savings, the net impact of the rate increase on consumers was about $99 million. LP&L implemented the increase on bills rendered on and after October 9, 1985, but this action made the increase retroactive to service rendered during the previous month. The Commission

ordered that LP&L discontinue this practice and refund the retroactive collections and the matter is under litigation in the district court.

In this case, LP&L requests rate relief for its own nuclear project, the Waterford 3 nuclear station. This unit was placed in commercial operation in September, 1985. LP&L requests a gross rate increase of $444 million for the first-year cost of this unit. The net rate request, after reflecting fuel savings, is about $355 million.

The Commission has had before it three separate requests for rate relief for Waterford 3 during this calendar year. Both previous requests were dismissed prior to the commercial operation of the unit. The financial condition of the company was thoroughly analyzed by the staff and consultants of the Commission in the two previous dockets and the analysis has been updated in this docket. The Commission incorporates by reference the records compiled in two previous cases -- Docket U-16518 and U-16091.

Because of the emergency facing the company, the staff was directed to obtain information concerning its financial status and to submit a proposal for emergency rate relief, if relief was deemed necessary. Proposals from other interested parties were also solicited. These proposals were sought, however, in the following context: 1) the Commission

has up to a year to make a final determination of the rate application under Article 4, Section 21 of the Louisiana Constitution and is considering this application on an expedited basis, without the benefit of comprehensive hearings; 2) there is continuing litigation over the Grand Gulf 1 rate award of the district court and the application of the increase to service rendered prior to the date of the award; and 3) there is substantial concern over the prudence of the decision to construct and complete Waterford 3, particularly as it relates to the burden placed on LP&L vis-a-vis the other companies in the MSU System. In addition, the company has indicated a willingness to enter a negotiated settlement for emergency rate relief that would include a permanent disallowance of a portion of Waterford 3.

The staff analysis indicates that LP&L is currently operating at a loss. Expenses including preferred dividends are projected to exceed revenues for the next 12 months by about $111 million. Considering the effect of income taxes, a $215 million base rate increase, or $126 million after accounting for the $89 million in fuel savings from Waterford 3, would be required to place the company on a break-even basis, assuming a reasonable additional deferral or "phase in" of Waterford 3 costs.

In addition, the company faces the need to attract substantial amounts of capital in the near future. It must

refinance $75 million in first mortgage bonds that will mature in early January and finance a $56 million refund to consumers, relating to the Texaco settlement in February. The company also must finance a construction program, already pared to essentials, which will cost $150 million in the next year. Internally generated cash in all likelihood would not cover the construction program, assuming LP&L operated at the break even point. The SEC currently is not allowing the company to issue securities pending an improvement in its financial condition, which can only come through rate relief.

In light of these factors, the staff proposes that the company be allowed a $215 million base rate increase for Waterford 3. The net increase, after fuel savings, would be $126 million. The company would also be permitted to defer a total of $206 million of Waterford 3 costs. The first year increase includes first year carrying charges computed at a 13 per cent rate. The Commission would approve a phase-in of Waterford 3 costs, allowing the deferral and ultimate recovery of those costs not ultimately found imprudent, on a schedule to be determined by the Commission. Any finding of imprudence would operate prospectively. Carrying charges on all amounts deferred after the first year would be computed at a 10.2 per cent net-of-tax rate.

The Staff proposes that this increase be granted only if LP&L agrees to certain conditions, which would be imposed in light of the expedited consideration of the request, the pending litigation, the prudence issues relating to Waterford 3, and the settlement discussions. They are:

1) Middle South Energy, Inc. must agree to accept the permanent retained percentage (18%) of the LP&L share of Grand Gulf 1 under the terms outlined to the Commission, and offered by MSE, in July. This settlement would reduce the Grand Gulf revenue requirement by $19 million in the first year, reflecting a reduction in base rates of approximately $24 million and the recovery of 4.6 cents per kilowatt hour for the energy from the permanent retained percentage through the fuel clause ($5 million benefit). A minimum net annual reduction in rates of $15.6 million would be guaranteed by MSE for 10 years. Alternatively, if MSE refuses to accept this proposal, LP&L would absorb the 18 per cent reduction on the same terms. This agreement would settle the Grand Gulf appeal.

2) LP&L must agree to permanently absorb $284 million of the $2.84 billion of Waterford 3 cost regardless of the outcome of a prudency review.

3) The Commission may disallow an additional amount for imprudence in the construction and completion of Waterford 3, on a prospective basis, if a finding of imprudence is made after a prudence investigation. The finding would be subject to appeal. ~~The~~ disallowance would be limited to the amount by which the total imprudent investment exceeds $284 million.

4) LP&L must agree to refund all amounts billed for Grand Gulf based on service rendered prior to October 9, 1985.

5) LP&L must provide a letter from the Marine Midland Bank agreeing to move forward with the syndication of a letter of credit to allow the company to obtain $105 million in funds for low-interest pollution control bonds. The letter shall be satisfactory to the Secretary of the Commission.

6) LP&L must agree that the constitutional one-year period for analyzing the rate request shall restart beginning the date the emergency rate increase becomes effective. This proceeding will remain open for a full rate analysis and prudence review.

These actions would reduce the necessary "net" rate increase, after accounting for changes in fuel costs, to $106.7 million. The total base rate increase is $190.7 million. The $106.7 million "net" rate increase is less than one-third of the $355 million requested by the company.

In light of the precarious financial condition of LP&L and the relatively modest rate increase associated with the staff proposal, the Commission will approve the staff recommendation. The Commission will approve the recommended rate increase conditioned on the agreement by LP&L to the terms specified in this Order. The Commission will also approve the deferral plan proposed by the staff. The rate increase shall apply to service rendered after the effective date of the increase. Therefore, in consideration of the foregoing,

IT IS ORDERED that LP&L be and hereby is authorized to increase its rates in the amount of $106.7 million, but only after it has filed a statement with the Commission agreeing to the terms specified herein and filed the necessary letter from the Midland Marine Bank. The Commission approves the deferral plan proposed by the Staff, subject to the same conditions. The base rate increase shall be allocated among customer classes in proportion to the contribution of each class to the base revenues of the company in the test year. The increase shall be effective at the time specified in this Order.

BY ORDER OF COMMISSION
BATON ROUGE, LOUISIANA
NOVEMBER 14, 1985

George J. Cikel - Dissents but Concurs in the ordered refund
Commissioner

John F. Schwegmann
Commissioner

Commissioner

Commissioner

Commissioner

Louis S. Quinn
Secretary

EXHIBIT ____

Schedule (DJL-2)

Louisiana Public Service Commission

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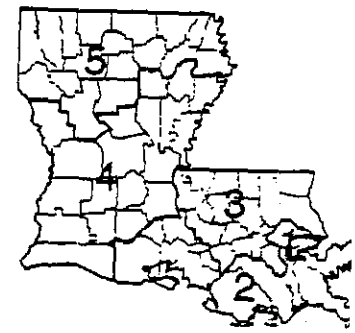
Telephone: (504)342-1405



LOUIS S. QUINN
Secretary

Gentlemen:

Enclosed herewith is the following request for proposal:

> In re: The decision of Louisiana Power and Light Company (LP&L) to construct a nuclear generating facility known as Waterford No. 3, the prudent construction costs thereof, and LP&L's decision to contract with Middle South Energy, Inc. (MSE) for capacity and energy to be supplied from MSE's nuclear generating unit.

Your firm is invited to submit a proposal to be received in this Office by January 3, 1986. Please state separately the fee. In connection with any proposal you may wish to submit, a personal appearance may be required before the Public Service Commission prior to the selection of the successful contractor. The successful contractor's fee will be assessed against the utility company under LSA R.S. 45:1180, et. seq.

No fee or expense reimbursement is payable by this Commission to any contractor who submits a request for proposal.

If you have any questions concerning this project please call the undersigned at 504/342-4427.

Yours very truly,

Louis S. Quinn
Secretary

LSQ/RFE/tmh

Enclosures

STATE OF LOUISIANA

PUBLIC SERVICE COMMISSION

REQUEST FOR PROPOSAL

I. Background

Louisiana Power and Light (LP&L) filed an application for an increase of some $444 million in its electric rates and charges. By statute, a decision must be rendered on this application no later than september 23, 1986. A previous increase of $113.9 million was granted by the Court on October 9, 1985 to cover the Grand Gulf No. 1 costs to LP&L.

The most significant cause of the rate increase requested is the commercial operation of the Waterford No. 3 nuclear unit. Since originally planned, the estimated total cost of Waterford 3 and Grand Gulf 1 have increased substantially such that they are now estimated to cost approximately $2500 per kilowatt of capacity.

The Commission is concerned with the accuracy, prudence and reasonableness of LP&L's cost estimates for the Waterford No. 3 Unit; the ultimate costs thereof; and, whether LP&L had the technical capability to prudently monitor the cost of this unit. The Commission is also concerned with the prudence of the contract for the purchase of power from the Grand Gulf Unit.

The Commission in open session on November 14, 1985, authorized the hiring of a consulting organization to assist it in answering these concerns.

II. Scope of Study

A report is to be furnished to the Commission which is to address each of the areas described below. It may be necessary to present and defend this report in a public hearing with those responsible for the report subject to cross-examination. The final report is to be provided no later than August 1, 1986. The report should contain ~~the firm's definition of prudency.~~ The successful firm will perform the following tasks:

A. Analyze and review the various construction cost estimates of the Waterford No. 3 Unit to determine whether:

The total cost is reasonable and prudent and not the result of defective or incomplete planning and monitoring of contractor charges.

B. Analyze and review LP&L's management capability to determine whether:

1) The decision to construct a nuclear unit of the size and capacity of Waterford 3 and the continuation of construction at the various stages of the revision of cost estimates was the exercise of reasonable and prudent judgement.
2) LP&L had sufficient managerial expertise to properly monitor the construction of the Waterford No. 3 Unit from a technical and financial perspective;
3) LP&L has the requisite expertise to successfully operate the unit; and
4) Proper procedures were in effect to ensure that the terms of its contracts for construction were being met and that LP&L has not

C. Analyze and review the circumstances surrounding the decision of LP&L to contract with Middle South Energy, Inc. for purchase of capacity and energy from the Grand Gulf Unit with specific emphasis on

1) The reasonableness and prudence of contracting for rather than building capacity at the time of the contract;

2) Whether the capacity was needed when the contract was confected;

3) Overall assessment of the reasonableness of management decision in entering into the contract.

D. Recommendations

Upon analysis and consideration of the above issues, the consultant will make recommendations in the following areas:

1) Should any portion of the cost of the Waterford No. 3 unit be deemed to be imprudently incurred and, if so, how much;

2) Should LP&L augment its management and technical capability in order to successfully operate the Waterford No. 3 unit;

3) Management competence in regard to any facet of the Grand Gulf agreement. The study should cover the need for purchased power from Grand Gulf No. 1 or other sources. Was any of the power contracted for in excess of LP&L's needs to meet the reasonable demands of its customers and maintain an adequate reserve.

4) The study should examine the need for Waterford No. 3. Was any of the power to be generated in excess of LP&L's needs to meet the reasonable demands of its customers and maintain an adequate reserve.

5) The study should establish which plants were to be retired; the schedule for such retirements; and whether such schedule was maintained. Consideration should be given to the load forecasts prepared at various times and how LP&L proposed to meet its peak demand. Would it have been more prudent to upgrade existing generating plants; construct coal or other generating units in lieu of deciding to construct the nuclear facility or, once the decision was made to construct the nuclear generating plant, was the decision re-visited to see whether it would have been prudent at any point in time to cancel the nuclear facility and select alternatives to meet the reasonable demands of its customers and provide an adequate reserve margin.

6) In considering demand forecasts, did the Company consider the effects on demand of requested rate increases; conservation measures or cogeneration.

7) The study should consider the impact on the final cost of the Waterford No. 3 project of Nuclear Regulatory Commission decisions and, or, inspections. A determination should be made whether or not these additional costs could have been avoided by prudent action by the Management of LP&L.

8) The study should make a finding as to whether there was any under utilization of equipment or personnel by LP&L in connection with the construction of Waterford No. 3 which added to the final costs.

9) In each instance where a finding of imprudence is made by the successful firm, the cost of such imprudence should be quantified.

III. Capabilities of Consultant

Because of the complexities of the above listed tasks, the Commission must ensure that the consultant has the requisite background and expertise.

A. Therefore, the consultant should evidence expertise in the following areas:

1) Familiarity with and understanding of nuclear technology;

2) Familiarity with and understanding of construction cost accounting and verification; and

3) Familiarity with and understanding of the regulatory and ratemaking process.

4) Familiarity with and understanding of management practices of large public utilities.

5) Familiarity and understanding of board functions and alternative sources of power supply.

6) Previous studies of this nature which the firm has undertaken.

B. To aid the Commission in selecting a consultant, the following information is to be provided:

1) A summary of the firm and its members;

2) A detailed description of the educational background and professional experience of the individuals to be directly involved in this project;

3) The per diem rates that would be charged;

4) The total cost that would be charged, indicating separately the per diem charges and reimbursement for incurred expenses; and

5) The type of contract to be offered, i.e., fixed price or other.

EXHIBIT ____

Schedule (DJL-3)

Louisiana Public Service Commission

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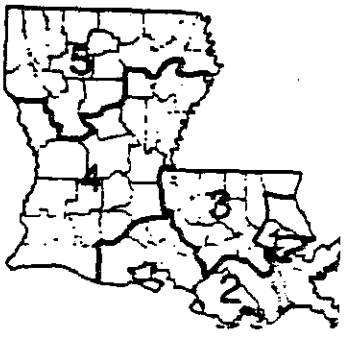
Telephone:
(504)342-1433



May 1, 1986

Theodore Barry & Associates
a T B & A Group Company
1520 Wilshire Boulevard
Los Angeles, CA 90017

In re: Prudency review of Louisiana Power & Light Company

Gentlemen:

This Commission, as you know, has selected your Firm to perform a complete prudency investigation of the decision of Louisiana Power & Light Company (LP&L) to construct a nuclear generating facility known as Waterford No. 3; the prudent construction costs thereof; and, LP&L's decision to contract with Middle South Energy, Inc. (MSE) for capacity and energy to be supplied from MSE's nuclear generating unit.

In its request for proposal, the Commission included the following item at page 4:

> "5) The study should establish which plants were to be retired; and whether such schedule was maintained. Consideration should be given to the load forecasts prepared at various times and how LP&L proposed to meet its peak demand. Would it have been more prudent to upgrade existing generating plants; construct coal or other generating units in lieu of deciding to construct the nuclear facility or, once the decision was made to construct the nuclear generating plant, was the decision re-visited to see whether it would have been prudent at any point in time to cancel the nuclear facility and select alternatives to meet the reasonable demands of its customers and provide an adequate reserve margin."

To insure that the Commission receives all the information it wishes to receive following your study, the Commission wants to be advised that, at each point in time during the history of the construction of the Waterford No. 3 nuclear generating unit, when LP&L did a study of its option, i.e., cancel the

construction, select alternatives such as coal or lignite, or upgrade existing facilities, the Commission wants to be advised as to the basis on which the decision was made to continue to construct Waterford No. 3. Your report should cover the least cost life cycle economic analysis of building nuclear, coal, lignite, etc. as part of your economic analysis of the LP&L decisions made at various times to continue to build the nuclear generating plant.

Attached is a letter from the Jefferson Parish Attorney in which he suggested certain things be done by your Firm to insure that a complete prudency investigation is undertaken.

Yours very truly,

Louis S. Quinn
Secretary

Enclosures

LSQ:mbg

cc: All parties on official service list - Docket No. U- 16945

JEFFERSON PARISH
LOUISIANA

ANTHONY R. MESSINA
PARISH ATTORNEY

April 28, 1986

NEW COURTHOUSE
P.O. BOX 9
GRETNA, LA 70054
TELEPHONE:
(504) 367-6611, X-361

PROPERTY ACQUISITION
X-338

Mr. Roy F. Edwards
Chief Auditor
Louisiana Public Service Commission
One American Place
Suite 1630
Baton Rouge, LA 70825

Dear Mr. Edwards:

In response to your letter dated March 20, 1986, to all intervenors, I am offering the following comments to the Louisiana Public Service Commission concerning the prudency review of the Louisiana Power and Light Company's Waterford No. 3 construction program and related matters:

Definition of Prudency - The Commissions's RFP in Section 2, Scope of Study requires that the selected firm provide its definition of prudency. The Scope then goes on to discuss the areas which the Commission desires to be explored. Most current prudency investigations utilize the "reasonable man approach" which focuses on the actions of the company being examined by inquiring as to whether or not the company's conduct was reasonable at that time, under the circumstances, giving consideration to the fact that the company was required to solve its problems prospectively rather than in reliance on hindsight (i.e., determining how reasonable people would have performed the task that confronted the company at the time of the occurrence). It is important in conducting an objective prudency examination that the regulatory commission does not view responses of the company to historical occurrences with the benefit of hindsight that would not have been available to the company as it proceeded with a construction effort. Generally, prudency examinations have been conducted to determine whether construction methods and decisions of the company's management and the costs associated with those methods and decisions were prudent, under the circumstances that prevailed at the time those methods were employed and those decisions rendered. (Thus - the reasonable man approach.)

Areas of Prudency Review - A prudency review of a given project should consist of three basic areas, namely, (1) the contracts relating to the constructing of the project and the relative costing of those contracts, (2) the design and

construction of the project, and (3) management's goals and objectives which directly influenced the project. The general areas of prudency review consist of an examination of the company in the discharge of its responsibilities with respect to project planning and management, engineering and design, construction management, quality control programs, licensing proceedings and regulations. Inherent in such an examination is the difficult determination of the question of the levels of productivity which existed throughout the history of the construction of a particular project.

A review of the contracts executed for the project should include analyses regarding the contractual arrangements. Such analyses should clearly answer the questions as to who were the responsible parties regarding various contingencies of the project. Did the contracts contain provisions for arbitration of differences between the parties? How are changes in design and/or construction reflected in the contract arrangements? Are factors reflecting cost controls such as labor contracts, overtime policies, project schedules, cost plus or fixed fee arrangements adequately delineated in the contracts? What method of remedies in case of contract breach? During the design and construction of the project, did the primary party have adequate personnel with the proper skill level to perform the various required tasks and functions? What types of quality control procedures and methods were utilized to manage and review the project? How were changes in design either prior or during construction handled in the process?

The proceeding two categories, contracts/costs and design/construction, are obliquely addressed n the LPSC's November 1985 RFP. However, the third major category which should be contained in a prudency review namely, identification and analysis regarding the management's goals and objectives for the project was only casually addressed in the LPSC's RFP. It is management's goals and objectives which set the direction and style of the contracts, costs, design and construction of a project. The primary objective of management should be identified and analyzed in order to properly determine prudency of a project. How management also measured results of its project compared to its objective is of extreme importance. The method of measurement can and does influence the results. Equally important are the methodologies used to gather the data for measurement of the objectives. Did management review its goals and objectives on a regular ongoing basis to make proper modifications during the project? The LPSC RFP does ask for information regarding whether or not LP&L revisited its decision to build Waterford No. 3 and only in an oblique way

addresses the whole prudency to construct issue. The suggested letter to Theodore, Barry & Associates by the LPSC states that the report should cover the least cost life cycle economic analysis of building various power supply alternatives available to LP&L. Until the goals and objectives of management on building the Waterford plant are properly defined, the type of economic analysis needed to review those goals and objectives cannot be defined without possibly effecting the results of the study. For example, suppose the primary objective and goal of the company was to diversify its fuel mix in order to remove supply uncertainties. If its then current fuel mix was its least cost source, any other fuel would not be an economic alternative. In that case, an economic life cycle analysis would show the decision to be prudent. However, in reality, if the original management objective and goal was deemed prudent, then an economic life cycle analysis would not be a reasonable method for measuring performance of the goal and objective.

In conclusion, Jefferson Parish takes the position that the comments expressed should be considered seriously by the LPSC as it relates to its desire to conduct a full prudency examination on the construction of LP&L's nuclear generating facility, Waterford No. 3. The Parish was unable to furnish comments back to you prior to April 29, 1986. Consequently, in the spirit of attempting to assist the comments regarding its charge to Theodore, Barry & Associates concerning the prudency investigation, the Parish of Jefferson urges and requests that the Commission accept these comments and give them full consideration.

Thank you very much for your cooperation.

Sincerely,

Anthony R. Messina
Parish Attorney

ARM/mv
cc: All Commissioners
All Intervenors

EXHIBIT ____

Schedule (DJL-4)

AIF **Background INFO**

Public Affairs and Information Program

HISTORICAL PROFILE OF U.S. NUCLEAR POWER DEVELOPMENT

(January 1, 1986)

For commercial nuclear power reactors, this profile is a history of orders placed, licenses issued, cancellations and retirements from the industry's beginnings in 1953 through 1985.

Reactor orders are listed by year and month, name, net megawatts electric (MWe) capacity, type, manufacturer and operating utility. For reactors subsequently cancelled, the date appears in the left-hand margin.

Reactors that received limited work authorizations, construction permits or operating licenses from the U.S. Nuclear Regulatory Commission are listed by year and month, name, net megawatts electric (MWe) capacity, type, manufacturer and operating utility. Reactors cancelled or retired from operation are indicated in the left-hand margin.

Reactor cancellations are listed by year, name, status (O — order, LWA — limited work authorization, C — construction permit), per cent of construction completed — if any, net megawatts electric (MWe) capacity, type, manufacturer and operating utility.

Reactors retired from operation are listed by year, name, years in operation, net megawatts electric (MWe) capacity, type, manufacturer and operating utility.

Reactor types listed:

BWR	boiling water reactor	LMFBR	liquid metal fast breeder reactor
FBR	fast breeder reactor	LWBR	light water breeder reactor
GR	graphite reactor	OMR	organic moderator reactor
HTGR	high temperature gas-cooled reactor	PWR	pressurized water reactor
HWR	heavy water reactor	SGR	sodium graphite reactor

Reactor manufacturers listed:

AC	Allis-Chalmers	GA	General Atomic
AI	Atomics International	GE	General Electric
B&W	Babcock & Wilcox	PRDC	Power Reactor Development Co.
CE	Combustion Engineering	W	Westinghouse

On page 20 is a handy, quick-reference table that summarizes pages 2-19 and shows the entire picture of historical U.S. nuclear power development.

For further information, contact Ellen Nunnelee, Economist, AIF, (301) 654-9260.

Atomic Industrial Forum, Inc.
7101 Wisconsin Avenue
Bethesda, MD 20814-4891
Telephone: (301) 654-9260

ORDERS PLACED

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1985				
	none				
	1984				
	none				
	1983				
	none				
	1982				
	none				
	1981				
	none				
	1980				
	none				
	1979				
	none				
	1978				
	Dec.	Carroll County 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Carroll County 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Total: 2 reactors = 2,240 MWe				
	1977				
cancelled '80	July	New Haven 1	1,250 MWe	PWR/CE	New York State Electric & Gas
cancelled '80	July	New Haven 2	1,250 MWe	PWR/CE	New York State Electric & Gas
cancelled '79	Aug.	Palo Verde 4	1,270 MWe	PWR/CE	Arizona Public Service
cancelled '79	Aug.	Palo Verde 5	1,270 MWe	PWR/CE	Arizona Public Service
	Total: 4 reactors = 5,040 MWe (Net total: 0)				
	1976				
cancelled '80	July	Erie 1	1,260 MWe	PWR/B&W	Ohio Edison
cancelled '80	July	Erie 2	1,260 MWe	PWR/B&W	Ohio Edison
cancelled '82	June	Vandalia	1,270 MWe	PWR/B&W	Iowa Power and Light
	Total: 3 reactors = 3,790 MWe (Net total: 0)				
	1975				
cancelled '77	May	South Dade 1	1,140 MWe	PWR/W	Florida Power & Light
cancelled '77	May	South Dade 2	1,140 MWe	PWR/W	Florida Power & Light
cancelled '78	July	Sundesert 1	950 MWe	PWR/W	San Diego Gas and Electric
cancelled '78	July	Sundesert 2	950 MWe	PWR/W	San Diego Gas and Electric
	Total: 4 reactors = 4,180 MWe (Net total: 0)				
	1974				
cancelled '75	Jan.	Alan Barton 3	1,170 MWe	BWR/GE	Alabama Power
cancelled '75	Jan.	Alan Barton 4	1,170 MWe	BWR/GE	Alabama Power
cancelled '78	May	Blue Hills 2	950 MWe	PWR/CE	Gulf States Utilities (TX)
cancelled '77	Aug.	Fort Calhoun 2	1,150 MWe	PWR/W	Omaha Public Power District
cancelled '79	June	Greene County	1,200 MWe	PWR/B&W	Power Authority of the State of New York
cancelled '80	Feb.	Jamesport 2	1,150 MWe	PWR/W	Long Island Lighting
cancelled '84	Aug.	Marble Hill 1	1,130 MWe	PWR/W	Public Service Indiana
cancelled '84	Aug.	Marble Hill 2	1,130 MWe	PWR/W	Public Service Indiana
cancelled '80	June	Montague 1	1,150 MWe	BWR/GE	Northeast Utilities (MA)
cancelled '80	June	Montague 2	1,150 MWe	BWR/GE	Northeast Utilities (MA)
cancelled '79	May	NEP-1	1,150 MWe	PWR/W	New England Power (RI)
cancelled '79	May	NEP-2	1,150 MWe	PWR/W	New England Power (RI)
cancelled '82	May	Pebble Springs 2	1,260 MWe	PWR/B&W	Portland General Electric
cancelled '82	Aug.	Phipps Bend 1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	Aug.	Phipps Bend 2	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '75	March	St. Rosalie 1	1,160 MWe	HTGR/GA	Louisiana Power & Light
cancelled '75	March	St. Rosalie 2	1,160 MWe	HTGR/GA	Louisiana Power & Light
cancelled '83	July	Skagit 2	1,275 MWe	BWR/GE	Puget Sound Power and Light (WA)
cancelled '77	Nov.	unit 1	1,150 MWe	PWR/W	Central Maine Power
cancelled '75	March	unit 1	1,300 MWe	PWR/CE	Florida Power
cancelled '75	March	unit 2	1,300 MWe	PWR/CE	Florida Power
cancelled '82	July	WPPSS 4	1,250 MWe	PWR/B&W	Washington Public Power Supply System
cancelled '82	July	WPPSS 5	1,240 MWe	PWR/CE	Washington Public Power Supply System
cancelled '84	Aug.	Yellow Creek 1	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
cancelled '84	Aug.	Yellow Creek 2	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
cancelled '78	Jan.	Wm. H. Zimmer 2	1,150 MWe	BWR/GE	Cincinnati Gas & Electric
	Total: 26 reactors = 30,931 MWe (Net total: 0)				

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1973				
cancelled '82	March	Allens Creek 1	1,200 MWe	BWR/GE	Houston Lighting & Power
cancelled '76	March	Allens Creek 2	1,150 MWe	BWR/GE	Houston Lighting & Power
cancelled '82	Dec.	Black Fox 1	1,150 MWe	BWR/GE	Public Service of Oklahoma
cancelled '82	Dec.	Black Fox 2	1,150 MWe	BWR/GE	Public Service of Oklahoma
cancelled '78	Feb.	Blue Hills 1	950 MWe	PWR/CE	Gulf States Utilities (TX)
	July	Callaway 1	1,150 MWe	PWR/W	Union Electric (MO)
cancelled '81	July	Callaway 2	1,150 MWe	PWR/W	Union Electric (MO)
cancelled '83	April	Cherokee 1	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	April	Cherokee 2	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	April	Cherokee 3	1,280 MWe	PWR/CE	Duke Power (SC)
	Jan.	Clinton 1	933 MWe	BWR/GE	Illinois Power
cancelled '83	Jan.	Clinton 2	933 MWe	BWR/GE	Illinois Power
cancelled '80	Dec.	Davis-Besse 2	906 MWe	PWR/B&W	Toledo Edison
cancelled '80	Dec.	Davis-Besse 3	906 MWe	PWR/B&W	Toledo Edison
cancelled '80	July	Haven 1	900 MWe	PWR/W	Wisconsin Electric Power
cancelled '78	July	Haven 2	900 MWe	PWR/W	Wisconsin Electric Power
cancelled '80	June	Jamesport 1	1,150 MWe	PWR/W	Long Island Lighting
	Feb.	Millstone 3	1,150 MWe	PWR/W	Northeast Nuclear Energy (CT)
	Oct.	Palo Verde 1	1,270 MWe	PWR/CE	Arizona Public Service
	Oct.	Palo Verde 2	1,270 MWe	PWR/CE	Arizona Public Service
	Oct.	Palo Verde 3	1,270 MWe	PWR/CE	Arizona Public Service
cancelled '82	Feb.	Pebble Springs 1	1,260 MWe	PWR/B&W	Portland General Electric
cancelled '82	April	Thomas L. Perkins 1	1,280 MWe	PWR/CE	Duke Power (NC)
cancelled '82	April	Thomas L. Perkins 2	1,280 MWe	PWR/CE	Duke Power (NC)
cancelled '82	April	Thomas L. Perkins 3	1,280 MWe	PWR/CE	Duke Power (NC)
cancelled '84	Sept.	River Bend 2	934 MWe	BWR/GE	Gulf States Utilities (LA)
cancelled '83	Dec.	Skagit 1	1,275 MWe	BWR/GE	Puget Sound Power and Light (WA)
cancelled '78	Dec.	S.R. 1	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
cancelled '78	Dec.	S.R. 2	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
cancelled '74	Dec.	S.R. 3	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
	July	South Texas Project 1	1,250 MWe	PWR/W	Houston Lighting & Power
	July	South Texas Project 2	1,250 MWe	PWR/W	Houston Lighting & Power
cancelled '80	July	Sterling	1,150 MWe	PWR/W	Rochester Gas and Electric
cancelled '79	July	Tyrone 1	1,100 MWe	PWR/W	Northern States Power (WI)
cancelled '74	July	Tyrone 2	1,100 MWe	PWR/W	Northern States Power (WI)
cancelled '78	Nov.	unit 1 (offshore)	1,150 MWe	PWR/W	Public Service Electric and Gas (NJ)
cancelled '78	Nov.	unit 2 (offshore)	1,150 MWe	PWR/W	Public Service Electric and Gas (NJ)
cancelled '74	July	Alvin W. Vogtle 3	1,100 MWe	PWR/W	Georgia Power
cancelled '74	July	Alvin W. Vogtle 4	1,100 MWe	PWR/W	Georgia Power
	July	Wolf Creek	1,150 MWe	PWR/W	Kansas Gas and Electric
	July	WPPSS 3	1,240 MWe	PWR/CE	Washington Public Power Supply System
	Total: 41 reactors = 46,827 MWe (Net total: 10 reactors = 11,933 MWe)				
	1972				
cancelled '78	Sept.	Atlantic 1 (offshore)	1,150 MWe	PWR/W	Public Service Electric and Gas (NJ)
cancelled '78	Sept.	Atlantic 2 (offshore)	1,150 MWe	PWR/W	Public Service Electric and Gas (NJ)
cancelled '77	Dec.	Alan Barton 1	1,170 MWe	BWR/GE	Alabama Power
cancelled '77	Dec.	Alan Barton 2	1,170 MWe	BWR/GE	Alabama Power
	Sept.	Braidwood 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Sept.	Braidwood 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	July	Catawba 1	1,145 MWe	PWR/W	Duke Power (SC)
	July	Catawba 2	1,145 MWe	PWR/W	Duke Power (SC)
	Oct.	Comanche Peak 1	1,150 MWe	PWR/W	Texas Utilities Generating
	Oct.	Comanche Peak 2	1,150 MWe	PWR/W	Texas Utilities Generating
cancelled '83	Nov.	CRBRP	375 MWe	LMFBR/W	U.S. Department of Energy (TN)
cancelled '77	Sept.	Douglas Point 1	1,178 MWe	BWR/GE	Potomac Electric Power (MD)
cancelled '76	Sept.	Douglas Point 2	1,178 MWe	BWR/GE	Potomac Electric Power (MD)
cancelled '74	May	Eastern Desert 1	770 MWe	HTGR/GA	Southern California Edison
cancelled '74	May	Eastern Desert 2	770 MWe	HTGR/GA	Southern California Edison
cancelled '75	Jan.	Enrico Fermi 3	1,171 MWe	BWR/GE	Detroit Edison
	Jan.	Grand Gulf 1	1,250 MWe	BWR/GE	Mississippi Power & Light
	Jan.	Grand Gulf 2	1,250 MWe	BWR/GE	Mississippi Power & Light
cancelled '80	April	Greenwood 2	1,264 MWe	PWR/B&W	Detroit Edison
cancelled '80	April	Greenwood 3	1,264 MWe	PWR/B&W	Detroit Edison
cancelled '84	Dec.	Hartsville A-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '84	Dec.	Hartsville A-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	Dec.	Hartsville B-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	Dec.	Hartsville B-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
	June	Perry 1	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
	June	Perry 2	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
cancelled '72	—	Perryman 1	880 MWe	PWR/CE	Baltimore Gas and Electric
cancelled '72	—	Perryman 2	880 MWe	PWR/CE	Baltimore Gas and Electric

Orders
4

		Unit	Net MWe	Type/Mfr.	Operating Utility
1972 continued					
cancelled '81	March	Pilgrim 2	1,150 MWe	PWR/CE	Boston Edison
cancelled '74	Dec.	Quanicassee 1	1,150 MWe	PWR/W	Consumers Power (MI)
cancelled '74	Dec.	Quanicassee 2	1,150 MWe	PWR/W	Consumers Power (MI)
	June	River Bend 1	934 MWe	BWR/GE	Gulf States Utilities (LA)
	Nov.	St. Lucie 2	786 MWe	PWR/CE	Florida Power & Light
	June	Seabrook 1	1,150 MWe	PWR/W	Public Service of New Hampshire
	June	Seabrook 2	1,150 MWe	PWR/W	Public Service of New Hampshire
cancelled '77	Sept.	Surry 3	882 MWe	PWR/W	Virginia Electric and Power
cancelled '77	Sept.	Surry 4	882 MWe	PWR/W	Virginia Electric and Power
	Nov.	WPPSS 1	1,250 MWe	PWR/B&W	Washington Public Power Supply System
	Total: 38 reactors = 41,526 MWe (Net total: 15 reactors = 17,010 MWe)				
	1971				
	Sept.	Beaver Valley 2	836 MWe	PWR/W	Duquesne Light (PA)
	April	Byron 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	April	Byron 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
cancelled '72	—	Crystal River 4	910 MWe	PWR/B&W	Florida Power
cancelled '75	Aug.	Fulton 1	1,160 MWe	HTGR/GA	Philadelphia Electric
cancelled '75	Aug.	Fulton 2	1,160 MWe	HTGR/GA	Philadelphia Electric
	April	Shearon Harris 1	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '83	April	Shearon Harris 2	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	April	Shearon Harris 3	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	April	Shearon Harris 4	900 MWe	PWR/W	Carolina Power & Light (NC)
	Sept.	Nine Mile Point 2	1,080 MWe	BWR/GE	Niagara Mohawk Power
cancelled '82	April	North Anna 3	907 MWe	PWR/B&W	Virginia Electric and Power
cancelled '80	April	North Anna 4	907 MWe	PWR/B&W	Virginia Electric and Power
	Feb.	Virgil C. Summer 1	900 MWe	PWR/W	South Carolina Electric & Gas
cancelled '75	Dec.	Summit 1	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
cancelled '75	Dec.	Summit 2	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
cancelled '79	Feb.	unit 1	1,168 MWe	BWR/GE	Pacific Gas and Electric (CA)
cancelled '79	Feb.	unit 2	1,168 MWe	BWR/GE	Pacific Gas and Electric (CA)
	Sept.	Alvin W. Vogtle 1	1,100 MWe	PWR/W	Georgia Power
	Sept.	Alvin W. Vogtle 2	1,100 MWe	PWR/W	Georgia Power
	March	WPPSS 2	1,100 MWe	BWR/GE	Washington Public Power Supply System
	Total: 21 reactors = 20,676 MWe (Net total: 9 reactors = 9,256 MWe)				
	1970				
	May	Arkansas Nuclear One-2	912 MWe	PWR/CE	Arkansas Power & Light
	Aug.	Bellefonte 1	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	Aug.	Bellefonte 2	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	Dec.	Joseph M. Farley 2	860 MWe	PWR/W	Alabama Power
	Feb.	Edwin I. Hatch 2	790 MWe	BWR/GE	Georgia Power
cancelled '78	May	Islote	583 MWe	PWR/W	Puerto Rico Water Resources Authority
	May	LaSalle 1	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
	May	LaSalle 2	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
	Jan.	North Anna 2	890 MWe	PWR/W	Virginia Electric Power
	Jan.	San Onofre 2	1,100 MWe	PWR/CE	Southern California Edison
	Jan.	San Onofre 3	1,100 MWe	PWR/CE	Southern California Edison
	Sept.	Waterford 3	1,104 MWe	PWR/CE	Louisiana Power & Light
	Aug.	Watts Bar 1	1,177 MWe	PWR/W	Tennessee Valley Authority
	Aug.	Watts Bar 2	1,177 MWe	PWR/W	Tennessee Valley Authority
	Total: 14 reactors = 14,275 MWe (Net total: 13 reactors = 13,692 MWe)				
	1969				
	May	Joseph M. Farley 1	860 MWe	PWR/W	Alabama Power
cancelled '80	Dec.	Forked River 1	1,168 MWe	PWR/CE	Jersey Central Power & Light
	Aug.	Hope Creek 1	1,067 MWe	BWR/GE	Public Service Electric and Gas (NJ)
cancelled '81	Aug.	Hope Creek 2	1,067 MWe	BWR/GE	Public Service Electric and Gas (NJ)
	Nov.	William McGuire 1	1,180 MWe	PWR/W	Duke Power (NC)
	Nov.	William McGuire 2	1,180 MWe	PWR/W	Duke Power (NC)
cancelled '84	Sept.	Wm. H. Zimmer 1	810 MWe	BWR/GE	Cincinnati Gas & Electric
	Total: 7 reactors = 7,332 MWe (Net total: 4 reactors = 4,287 MWe)				
	1968				
	Jan.	Brunswick 1	790 MWe	BWR/GE	Carolina Power & Light (NC)
	Jan.	Brunswick 2	790 MWe	BWR/GE	Carolina Power & Light (NC)
	Oct.	Davis-Besse 1	890 MWe	PWR/B&W	Toledo Edison
	July	Diablo Canyon 2	1,106 MWe	PWR/W	Pacific Gas & Electric (CA)
	Feb.	Duane Arnold	538 MWe	BWR/GE	Iowa Electric Light and Power
	Aug.	Enrico Fermi 2	1,139 MWe	BWR/GE	Detroit Edison
	Dec.	James A. Fitzpatrick	821 MWe	BWR/GE	New York Power Authority
	May	Midland 1	425 MWe	PWR/B&W	Consumers Power (MI)
	May	Midland 2	808 MWe	PWR/B&W	Consumers Power (MI)

	Unit		Net MWe	Type/Mfr.	Operating Utility
	1968 continued				
cancelled '72	—	Nuclear 4	1,115 MWe	BWR/GE	Consolidated Edison of New York, Inc.
cancelled '72	—	Nuclear 5	1,115 MWe	BWR/GE	Consolidated Edison of New York, Inc.
	April	Sequoyah 1	1,148 MWe	PWR/W	Tennessee Valley Authority
	April	Sequoyah 2	1,148 MWe	PWR/W	Tennessee Valley Authority
	May	Susquehanna 1	1,050 MWe	BWR/GE	Pennsylvania Power & Light
	May	Susquehanna 2	1,050 MWe	BWR/GE	Pennsylvania Power & Light
	Nov.	Trojan	1,130 MWe	PWR/W	Portland General Electric
	Total: 16 reactors = 15,063 MWe (Net total: 14 reactors = 12,833 MWe)				
	1967				
	April	Arkansas Nuclear One-1	850 MWe	PWR/B&W	Arkansas Power & Light
cancelled '81	Jan.	Bailly Nuclear 1	844 MWe	BWR/GE	Northern Indiana Public Service
	Sept.	Beaver Valley 1	833 MWe	PWR/W	Duquesne Light (PA)
cancelled '72	March	Bell	838 MWe	BWR/GE	New York State Electric & Gas
	June	Browns Ferry 3	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
	May	Calvert Cliffs 1	845 MWe	PWR/CE	Baltimore Gas and Electric
	May	Calvert Cliffs 2	845 MWe	PWR/CE	Baltimore Gas and Electric
	July	Donald C. Cook 1	1,030 MWe	PWR/W	Indiana & Michigan Electric (MI)
	July	Donald C. Cook 2	1,100 MWe	PWR/W	Indiana & Michigan Electric (MI)
	April	Cooper	778 MWe	BWR/GE	Nebraska Public Power District
	Feb.	Crystal River 3	880 MWe	PWR/B&W	Florida Power
	Dec.	Edwin I. Hatch 1	786 MWe	BWR/GE	Georgia Power
	April	Indian Point 3	965 MWe	PWR/W	New York Power Authority
	Feb.	Kewaunee	535 MWe	PWR/W	Wisconsin Public Service
	Oct.	Limerick 1	1,055 MWe	BWR/GE	Philadelphia Electric
	Oct.	Limerick 2	1,055 MWe	BWR/GE	Philadelphia Electric
	Feb.	Maine Yankee	825 MWe	PWR/CE	Maine Yankee Atomic Power
	Dec.	Millstone 2	869 MWe	PWR/CE	Northeast Utilities (CT)
	Oct.	North Anna 1	877 MWe	PWR/W	Virginia Electric and Power
	May	Oconee 3	860 MWe	PWR/B&W	Duke Power (SC)
	Feb.	Point Beach 2	497 MWe	PWR/W	Wisconsin Electric Power (WI)
	Feb.	Prairie Island 1	530 MWe	PWR/W	Northern States Power (MN)
	June	Prairie Island 2	530 MWe	PWR/W	Northern States Power (MN)
	Aug.	Rancho Seco 1	918 MWe	PWR/B&W	Sacramento Municipal Utility Dist.
	Dec.	St. Lucie 1	822 MWe	PWR/CE	Florida Power & Light
	May	Salem 2	1,115 MWe	PWR/B&W	Public Service Electric and Gas (NJ)
	Feb.	Shoreham	846 MWe	BWR/GE	Long Island Lighting
	Feb.	Three Mile Island 2	906 MWe	PWR/B&W	Metropolitan Edison (PA)
	April	Turkey Point 4	666 MWe	PWR/W	Florida Power & Light
	Feb.	Zion 1	1,040 MWe	PWR/W	Commonwealth Edison (IL)
	July	Zion 2	1,040 MWe	PWR/W	Commonwealth Edison (IL)
	Total: 31 reactors = 26,447 MWe (Net total: 29 reactors = 24,965 MWe)				
	1966				
	June	Browns Ferry 1	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
	June	Browns Ferry 2	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
	Nov.	Diablo Canyon 1	1,084 MWe	PWR/W	Pacific Gas & Electric (CA)
	Jan.	Dresden 3	794 MWe	BWR/GE	Commonwealth Edison (IL)
	Oct.	Fort Calhoun 1	486 MWe	PWR/CE	Omaha Public Power District
	April	Monticello	545 MWe	BWR/GE	Northern States Power (MN)
	July	Oconee 1	860 MWe	PWR/B&W	Duke Power (SC)
	July	Oconee 2	860 MWe	PWR/B&W	Duke Power (SC)
	Jan.	Palisades	757 MWe	PWR/CE	Consumers Power (MI)
	Aug.	Peach Bottom 2	1,065 MWe	BWR/GE	Philadelphia Electric
	Aug.	Peach Bottom 3	1,065 MWe	BWR/GE	Philadelphia Electric
	Feb.	Point Beach 1	497 MWe	PWR/W	Wisconsin Electric Power (WI)
	April	Quad Cities 1	789 MWe	BWR/GE	Commonwealth Edison (IL)
	July	Quad Cities 2	789 MWe	BWR/GE	Commonwealth Edison (IL)
	Jan.	H.B. Robinson 2	665 MWe	PWR/W	Carolina Power & Light (SC)
	Aug.	Salem 1	1,090 MWe	PWR/W	Public Service Electric and Gas (NJ)
	Oct.	Surry 1	775 MWe	PWR/W	Virginia Electric and Power
	Oct.	Surry 2	775 MWe	PWR/W	Virginia Electric and Power
	Nov.	Three Mile Island 1	819 MWe	PWR/B&W	Metropolitan Edison (PA)
	Aug.	Vermont Yankee	514 MWe	BWR/GE	Vermont Yankee Nuclear Power
	Total: 20 reactors = 16,363 MWe				
	1965				
	Feb.	Dresden 2	794 MWe	BWR/GE	Commonwealth Edison (IL)
	March	Fort St. Vrain	330 MWe	HTGR/GA	Public Service of Colorado
	Aug.	Robert E. Ginna	470 MWe	PWR/W	Rochester Gas and Electric
	Nov.	Indian Point 2	873 MWe	PWR/W	Consoldiated Edison of New York, Inc.
	Sept.	Millstone 1	660 MWe	BWR/GE	Northeast Utilities (CT)
	Aug.	Pilgrim 1	670 MWe	BWR/GE	Boston Edison
	Nov.	Turkey Point 3	666 MWe	PWR/W	Florida Power & Light
	Total: 7 reactors = 4,463 MWe				

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1964				
	none				
	1963				
	April	Hanford-N	860 MWe	GR/GE	DOE & Washington Public Power Supply System
	Oct.	Nine Mile Point 1	620 MWe	BWR/GE	Niagara Mohawk Power
	Dec.	Oyster Creek	650 MWe	BWR/GE	Jersey Central Power & Light
	Jan.	San Onofre 1	436 MWe	PWR/W	Southern California Edison
	Total: 4 reactors = 2,566 MWe				
	1962				
	Dec.	Haddam Neck	582 MWe	PWR/W	Connecticut Yankee Atomic Power
	June	LaCrosse	50 MWe	BWR/AC	Dairyland Power Coop. (WI)
	Total: 2 reactors = 632 MWe				
	1961				
	none				
	1960				
retired '68	Jan.	BONUS	17 MWe	BWR/CE	DOE & Puerto Rico Water Resources
	Total: 1 reactor = 17 MWe (Net total: 0)				
	1959				
	Dec.	Big Rock Point	63 MWe	BWR/GE	Consumers Power (MI)
retired '67	Jan.	CVTR	17 MWe	HWR/W	Carolinas-Virginia Nuclear Power Assoc. (SC)
retired '66	June	Piqua	11 MWe	OMR/AI	DOE & City of Piqua, Ohio
	Total: 3 reactors = 91 MWe (Net total: 1 reactor = 63 MWe)				
	1958				
retired '68	June	Elk River	22 MWe	BWR/AC	DOE & Rural Cooperative Power Assoc. (MN)
retired '83	Feb.	Humboldt Bay	65 MWe	BWR/GE	Pacific Gas & Electric (CA)
retired '74	Nov.	Peach Bottom 1	40 MWe	HTGR/GA	Philadelphia Electric
	Total: 3 reactors = 127 MWe (Net total: 0)				
	1957				
retired '64	Sept.	Hallam	75 MWe	SGR/AI	DOE & Consumers Public Power District (NE)
retired '67	May	Pathfinder	59 MWe	BWR/AC	Northern States Power (SC)
	Total: 2 reactors = 134 MWe (Net total: 0)				
	1956				
	June	Yankee Rowe	175 MWe	PWR/W	Yankee Atomic Electric (MA)
	Total: 1 reactor = 175 MWe				
	1955				
retired '84	July	Dresden 1	207 MWe	BWR/GE	Commonwealth Edison (IL)
retired '72	April	Enrico Fermi 1	61 MWe	FBR/PRDC	Power Reactor Development (MI)
retired '80	Feb	Indian Point 1	265 MWe	PWR/B&W	Consolidated Edison of New York, Inc.
	Total: 3 reactors = 533 MWe (Net total: 0)				
	1954				
	none				
	1953				
retired '82	July	Shippingport	60 MWe	LWBR/W	DOE & Duquesne Light (PA)
	Total: 1 reactor = 60 MWe (Net total: 0)				

LIMITED WORK AUTHORIZATIONS ISSUED

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1985				
	none				
	1984				
	none				
	1983				
cancelled '83	May	CRBRP	375 MWe	LMFBR/W	U.S. Department of Energy
	1982				
	none				
	1981				
	none				
	1980				
	none				
	1979				
	none				
	1978				
cancelled '82	July	Black Fox 1	1,150 MWe	BWR/GE	Public Service of Oklahoma
cancelled '82	July	Black Fox 2	1,150 MWe	BWR/GE	Public Service of Oklahoma
cancelled '84	Feb.	Yellow Creek 1	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
cancelled '84	Feb.	Yellow Creek 2	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
	Total: 4 reactors = 4,870 MWe (Net total: 0)				
	1977				
cancelled '84	Aug.	Marble Hill 1	1,130 MWe	PWR/W	Public Service Indiana
cancelled '84	Aug	Marble Hill 2	1,130 MWe	PWR/W	Public Service Indiana
cancelled '82	Oct.	Phipps Bend 1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	Oct.	Phipps Bend 2	1,233 MWe	BWR/GE	Tennessee Valley Authority
	April	WPPSS 3	1,240 MWe	PWR/CE	Washington Public Power Supply System
cancelled '82	April	WPPSS 5	1,240 MWe	PWR/CE	Washington Public Power Supply System
	Total: 6 reactors = 7,206 MWe (Net total: 1 reactor = 1,240 MWe)				
	1976				
cancelled '83	May	Cherokee 1	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	May	Cherokee 2	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	May	Cherokee 3	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '84	April	Hartsville A-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '84	April	Hartsville A-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	April	Hartsville B-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	April	Hartsville B-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
	Total: 7 reactors = 8,772 MWe (Net total: 0)				
	1975				
	Jan.	Braidwood 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Jan.	Braidwood 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Byron 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Byron 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Aug.	Callaway 1	1,150 MWe	PWR/W	Union Electric (MO)
cancelled '81	Aug.	Callaway 2	1,150 MWe	PWR/W	Union Electric (MO)
	Oct.	Clinton 1	933 MWe	BWR/GE	Illinois Power
cancelled '83	Oct.	Clinton 2	933 MWe	BWR/GE	Illinois Power
cancelled '80	Dec.	Davis-Besse 2	906 MWe	PWR/B&W	Toledo Edison
cancelled '80	Dec.	Davis-Besse 3	906 MWe	PWR/B&W	Toledo Edison
	Oct.	Perry 1	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
	Oct.	Perry 2	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
	Sept.	River Bend 1	934 MWe	BWR/GE	Gulf States Utilities (LA)
cancelled '84	Sept.	River Bend 2	934 MWe	BWR/GE	Gulf States Utilities (LA)
	March	St. Lucie 2	786 MWe	PWR/CE	Florida Power & Light
	Aug.	South Texas Project 1	1,250 MWe	PWR/W	Houston Lighting & Power
	Aug.	South Texas Project 2	1,250 MWe	PWR/W	Houston Lighting & Power
cancelled '75	Aug.	Summit 1	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
cancelled '75	Aug.	Summit 2	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
	Aug.	WPPSS 1	1,250 MWe	PWR/B&W	Washington Public Power Supply System
cancelled '82	Aug.	WPPSS 4	1,250 MWe	PWR/B&W	Washington Public Power Supply System
	Total: 21 reactors = 22,062 MWe (Net total: 13 reactors = 14,433 MWe)				

Limited Work Authorizations
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		Unit	Net MWe	Type/Mfr.	Operating Utility
	1974				
	Sept.	Bellefonte 1	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	Sept.	Bellefonte 2	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	May	Catawba 1	1,145 MWe	PWR/W	Duke Power (SC)
	May	Catawba 2	1,145 MWe	PWR/W	Duke Power (SC)
	Oct.	Comanche Peak 1	1,150 MWe	PWR/W	Texas Utilities Generating
	Oct.	Comanche Peak 2	1,150 MWe	PWR/W	Texas Utilities Generating
	May	Grand Gulf 1	1,250 MWe	BWR/GE	Mississippi Power & Light
	May	Grand Gulf 2	1,250 MWe	BWR/GE	Mississippi Power & Light
	Jan	Shearon Harris 1	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '83	Jan	Shearon Harris 2	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	Jan	Shearon Harris 3	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	Jan	Shearon Harris 4	900 MWe	PWR/W	Carolina Power & Light (NC)
	June	Millstone 3	1,150 MWe	PWR/W	Northeast Utilities (CT)
cancelled '77	Oct.	Surry 3	882 MWe	PWR/W	Virignia Electric and Power
cancelled '77	Oct.	Surry 4	882 MWe	PWR/W	Virginia Electric and Power
	May	Alvin W. Vogtle 1	1,100 MWe	PWR/W	Georgia Power
	May	Alvin W. Vogtle 2	1,100 MWe	PWR/W	Georgia Power
cancelled '74	May	Alvin W. Vogtle 3	1,100 MWe	PWR/W	Georgia Power
cancelled '74	May	Alvin W. Vogtle 4	1,100 MWe	PWR/W	Georgia Power
	May	Waterford 3	1,104 MWe	PWR/CE	Louisiana Power & Light

Total: 20 reactors = 21,534 MWe (Net total: 13 reactors = 14,870 MWe)

CONSTRUCTION PERMITS ISSUED

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1985				
	none				
	1984				
	none				
	1983				
	none				
	1982				
	none				
	1981				
	none				
	1980				
	none				
	1979				
cancelled '80	Jan.	Jamesport 1	1,150 MWe	PWR/W	Long Island Lighting
cancelled '80	Jan.	Jamesport 2	1,150 MWe	PWR/W	Long Island Lighting
	Total: 2 reactors = 2,300 MWe (Net total: 0)				
	1978				
	Jan.	Shearon Harris 1	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '83	Jan.	Shearon Harris 2	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	Jan.	Shearon Harris 3	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '81	Jan.	Shearon Harris 4	900 MWe	PWR/W	Carolina Power & Light (NC)
cancelled '84	April	Marble Hill 1	1,130 MWe	PWR/W	Public Service Indiana
cancelled '84	April	Marble Hill 2	1,130 MWe	PWR/W	Public Service Indiana
cancelled '82	Jan.	Phipps Bend 1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	Jan.	Phipps Bend 2	1,233 MWe	BWR/GE	Tennessee Valley Authority
	April	WPPSS 3	1,240 MWe	PWR/CE	Washington Public Power Supply System
cancelled '82	Feb.	WPPSS 4	1,250 MWe	PWR/B&W	Washington Public Power Supply System
cancelled '82	April	WPPSS 5	1,240 MWe	PWR/CE	Washington Public Power Supply System
cancelled '84	Nov.	Yellow Creek 1	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
cancelled '84	Nov.	Yellow Creek 2	1,285 MWe	PWR/CE	Tennessee Valley Authority (MS)
	Total: 13 reactors = 14,626 MWe (Net total: 2 reactors = 2,140 MWe)				
	1977				
cancelled '83	Dec.	Cherokee 1	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	Dec.	Cherokee 2	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '82	Dec.	Cherokee 3	1,280 MWe	PWR/CE	Duke Power (SC)
cancelled '84	May	Hartsville A-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '84	May	Hartsville A-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	May	Hartsville B-1	1,233 MWe	BWR/GE	Tennessee Valley Authority
cancelled '82	May	Hartsville B-2	1,233 MWe	BWR/GE	Tennessee Valley Authority
	May	Perry 1	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
	May	Perry 2	1,205 MWe	BWR/GE	Cleveland Electric Illuminating
	March	River Bend 1	934 MWe	BWR/GE	Gulf States Utilities (LA)
cancelled '84	March	River Bend 2	934 MWe	BWR/GE	Gulf States Utilities (LA)
	May	St. Lucie 2	786 MWe	PWR/CE	Florida Power & Light
cancelled '80	Sept.	Sterling	1,150 MWe	PWR/W	Rochester Gas and Electric
cancelled '79	Dec.	Tyrone 1	1,100 MWe	PWR/W	Northern States Power (WI)
	May	Wolf Creek	1,150 MWe	PWR/W	Kansas Gas and Electric
	Total: 15 reactors = 17,236 MWe (Net total: 5 reactors = 5,280 MWe)				
	1976				
	April	Callaway 1	1,150 MWe	PWR/W	Union Electric (MO)
cancelled '81	April	Callaway 2	1,150 MWe	PWR/W	Union Electric (MO)
	Feb.	Clinton 1	933 MWe	BWR/GE	Illinois Power
cancelled '83	Feb.	Clinton 2	933 MWe	BWR/GE	Illinois Power
	May	Palo Verde 1	1,270 MWe	PWR/CE	Arizona Public Service
	May	Palo Verde 2	1,270 MWe	PWR/CE	Arizona Public Service
	May	Palo Verde 3	1,270 MWe	PWR/CE	Arizona Public Service
	July	Seabrook 1	1,150 MWe	PWR/W	Public Service of New Hampshire
	July	Seabrook 2	1,150 MWe	PWR/W	Public Service of New Hampshire
	Total: 9 reactors = 10,276 MWe (Net total: 7 reactors = 8,193 MWe)				

Construction Permits
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		Unit	Net MWe	Type/Mfr.	Operating Utility
	1975				
	Dec.	Braidwood 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Braidwood 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Byron 1	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Dec.	Byron 2	1,120 MWe	PWR/W	Commonwealth Edison (IL)
	Aug	Catawba 1	1,145 MWe	PWR/W	Duke Power (SC)
	Aug.	Catawba 2	1,145 MWe	PWR/W	Duke Power (SC)
	Dec.	South Texas Project 1	1,250 MWe	PWR/W	Houston Lighting & Power
	Dec.	South Texas Project 2	1,250 MWe	PWR/W	Houston Lighting & Power
	Dec.	WPPSS 1	1,250 MWe	PWR/B&W	Washington Public Power Supply System
	Total: 9 reactors = 10,520 MWe				
	1974				
cancelled '81	May	Bailly Nuclear 1	644 MWe	BWR/GE	Northern Indiana Public Service
	May	Beaver Valley 2	836 MWe	PWR/W	Duquesne Light (PA)
	Dec.	Bellefonte 1	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	Dec.	Bellefonte 2	1,213 MWe	PWR/B&W	Tennessee Valley Authority (AL)
	Dec.	Comanche Peak 1	1,150 MWe	PWR/W	Texas Utilities Generating
	Dec.	Comanche Peak 2	1,150 MWe	PWR/W	Texas Utilities Generating
	Sept.	Grand Gulf 1	1,250 MWe	BWR/GE	Mississippi Power & Light
	Sept.	Grand Gulf 2	1,250 MWe	BWR/GE	Mississippi Power & Light
	Nov.	Hope Creek 1	1,067 MWe	BWR/GE	Public Service Electric and Gas (NJ)
cancelled '81	Nov.	Hope Creek 2	1,067 MWe	BWR/GE	Public Service Electric and Gas (NJ)
	June	Limerick 1	1,055 MWe	BWR/GE	Philadelphia Electric
	June	Limerick 2	1,055 MWe	BWR/GE	Philadelphia Electric
	Aug.	Millstone 3	1,150 MWe	PWR/W	Northeast Utilities (CT)
	June	Nine Mile Point 2	1,080 MWe	BWR/GE	Niagara Mohawk Power
cancelled '82	July	North Anna 3	907 MWe	PWR/B&W	Virginia Electric and Power
cancelled '80	July	North Anna 4	907 MWe	PWR/B&W	Virginia Electric and Power
cancelled '77	Dec.	Surry 3	882 MWe	PWR/W	Virginia Electric and Power
cancelled '77	Dec.	Surry 4	882 MWe	PWR/W	Virginia Electric and Power
	June	Alvin W. Vogtle 1	1,100 MWe	PWR/W	Georgia Power
	June	Alvin W. Vogtle 2	1,100 MWe	PWR/W	Georgia Power
cancelled '74	June	Alvin W. Vogtle 3	1,100 MWe	PWR/W	Georgia Power
cancelled '74	June	Alvin W. Vogtle 4	1,100 MWe	PWR/W	Georgia Power
	Nov.	Waterford 3	1,104 MWe	PWR/CE	Louisiana Power & Light
	Total: 23 reactors = 24,262 MWe (Net total: 15 reactors = 16,773 MWe)				
	1973				
cancelled '80	July	Forked River 1	1,168 MWe	PWR/CE	Jersey Central Power & Light
	Sept.	LaSalle 1	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
	Sept.	LaSalle 2	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
	Feb.	William McGuire 1	1,180 MWe	PWR/W	Duke Power (NC)
	Feb.	William McGuire 2	1,180 MWe	PWR/W	Duke Power (NC)
	Oct.	San Onofre 2	1,100 MWe	PWR/CE	Southern California Edison
	Oct.	San Onofre 3	1,100 MWe	PWR/CE	Southern California Edison
	April	Shoreham	846 MWe	BWR/GE	Long Island Lighting
	March	Virgil C. Summer I	900 MWe	PWR/W	South Carolina Electric & Gas
	Nov.	Susquehanna 1	1,050 MWe	BWR/GE	Pennsylvania Power & Light
	Nov.	Susquehanna 2	1,050 MWe	BWR/GE	Pennsylvania Power & Light
	Jan.	Watts Bar 1	1,177 MWe	PWR/W	Tennessee Valley Authority
	Jan.	Watts Bar 2	1,177 MWe	PWR/W	Tennessee Valley Authority
	March	WPPSS 2	1,100 MWe	BWR/GE	Washington Public Power Supply System
	Total: 14 reactors = 15,184 MWe (Net total: 13 reactors = 14,016 MWe)				
	1972				
	Dec.	Arkansas Nuclear One-2	912 MWe	PWR/CE	Arkansas Power & Light
	Aug.	Joseph M. Farley 1	860 MWe	PWR/W	Alabama Power
	Aug.	Joseph M. Farley 2	860 MWe	PWR/W	Alabama Power
	Sept.	Enrico Fermi 2	1,139 MWe	BWR/GE	Detroit Edison
	Dec.	Edwin I. Hatch 2	790 MWe	BWR/GE	Georgia Power
	Dec.	Midland 1	425 MWe	PWR/B&W	Consumers Power (MI)
	Dec.	Midland 2	808 MWe	PWR/B&W	Consumers Power (MI)
cancelled '84	Oct.	Wm. H. Zimmer 1	810 MWe	BWR/GE	Cincinnati Gas & Electric
	Total: 8 reactors = 6,804 MWe (Net total: 7 reactors = 5,794 MWe)				
	1971				
	March	Davis-Besse 1	890 MWe	PWR/B&W	Toledo Edison
	Feb.	North Anna 1	877 MWe	PWR/W	Virginia Electric and Power
	Feb.	North Anna 2	890 MWe	PWR/W	Virginia Electric and Power
	Feb.	Trojan	1,130 MWe	PWR/W	Portland General Electric
	Total: 4 reactors = 3,787 MWe				

	Unit	Net MWe	Type/Mfr.	Operating Utility
1970				
June	Beaver Valley 1	833 MWe	PWR/W	Duquesne Light (PA)
Feb.	Brunswick 1	790 MWe	BWR/GE	Carolina Power & Light (NC)
Feb.	Brunswick 2	790 MWe	BWR/GE	Carolina Power & Light (NC)
Dec.	Diablo Canyon 2	1,106 MWe	PWR/W	Pacific Gas & Electric (CA)
June	Duane Arnold	538 MWe	BWR/GE	Iowa Electric Light and Power
May	James A. Fitzpatrick	821 MWe	BWR/GE	New York Power Authority
Dec.	Millstone 2	869 MWe	PWR/CE	Northeast Utilities (CT)
July	St. Lucie 1	822 MWe	PWR/CE	Florida Power & Light
May	Sequoyah 1	1,148 MWe	PWR/W	Tennessee Valley Authority
May	Sequoyah 2	1,148 MWe	PWR/W	Tennessee Valley Authority
Total: 10 reactors = 8,865 MWe				
1969				
July	Calvert Cliffs 1	845 MWe	PWR/CE	Baltimore Gas and Electric
July	Calvert Cliffs 2	845 MWe	PWR/CE	Baltimore Gas and Electric
March	Donald C. Cook 1	1,030 MWe	PWR/W	Indiana & Michigan Electric (MI)
March	Donald C. Cook 2	1,100 MWe	PWR/W	Indiana & Michigan Electric (MI)
Sept.	Edwin I. Hatch 1	786 MWe	BWR/GE	Georgia Power
Aug.	Indian Point 3	965 MWe	PWR/W	New York Power Authority
Nov.	Three Mile Island 2	906 MWe	PWR/B&W	Metropolitan Edison (PA)
Total: 7 reactors = 6,477 MWe				
1968				
Dec.	Arkansas Nuclear One-1	850 MWe	PWR/B&W	Arkansas Power & Light
July	Browns Ferry 3	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
June	Cooper	778 MWe	BWR/GE	Nebraska Public Power District
Sept.	Crystal River 3	880 MWe	PWR/B&W	Florida Power
April	Diablo Canyon 1	1,084 MWe	PWR/W	Pacific Gas & Electric (CA)
June	Fort Calhoun 1	486 MWe	PWR/CE	Omaha Public Power District
Sept.	Fort St. Vrain	330 MWe	HTGR/GA	Public Service of Colorado
Aug.	Kewaunee	535 MWe	PWR/W	Wisconsin Public Service
Oct.	Maine Yankee	825 MWe	PWR/CE	Maine Yankee Atomic Power
Jan.	Peach Bottom 2	1,065 MWe	BWR/GE	Philadelphia Electric
Jan.	Peach Bottom 3	1,065 MWe	BWR/GE	Philadelphia Electric
Aug.	Pilgrim 1	670 MWe	BWR/GE	Boston Edison
July	Point Beach 2	497 MWe	PWR/W	Wisconsin Electric Power (WI)
June	Prairie Island 1	530 MWe	PWR/W	Northern States Power (MN)
June	Prairie Island 2	530 MWe	PWR/W	Northern States Power (MN)
Oct.	Rancho Seco 1	918 MWe	PWR/B&W	Sacramento Municipal Utility District
Sept.	Salem 1	1,090 MWe	PWR/W	Public Service Electric and Gas (NJ)
Sept.	Salem 2	1,115 MWe	PWR/W	Public Service Electric and Gas (NJ)
June	Surry 1	775 MWe	PWR/W	Virginia Electric and Power
June	Surry 2	775 MWe	PWR/W	Virginia Electric and Power
May	Three Mile Island 1	819 MWe	PWR/B&W	Metropolitan Edison (PA)
Dec.	Zion 1	1,040 MWe	PWR/W	Commonwealth Edison (IL)
Dec.	Zion 2	1,040 MWe	PWR/W	Commonwealth Edison (IL)
Total: 23 reactors = 18,764 MWe				
1967				
May	Browns Ferry 1	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
May	Browns Ferry 2	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
June	Monticello	545 MWe	BWR/GE	Northern States Power (MN)
Nov.	Oconee 1	860 MWe	PWR/B&W	Duke Power (SC)
Nov.	Oconee 2	860 MWe	PWR/B&W	Duke Power (SC)
Nov.	Oconne 3	860 MWe	PWR/B&W	Duke Power (SC)
March	Palisades	757 MWe	PWR/CE	Consumers Power (MI)
July	Point Beach 1	497 MWe	PWR/W	Wisconsin Electric Power (WI)
Feb.	Quad Cities 1	789 MWe	BWR/GE	Commonwealth Edison (IL)
Feb.	Quad Cities 2	789 MWe	BWR/GE	Commonwealth Edison (IL)
April	H.B. Robinson 2	665 MWe	PWR/W	Carolina Power & Light (SC)
April	Turkey Point 3	666 MWe	PWR/W	Florida Power & Light
April	Turkey Point 4	666 MWe	PWR/W	Florida Power & Light
Dec.	Vermont Yankee	514 MWe	BWR/GE	Vermont Yankee Nuclear Power
Total: 14 reactors = 10,602 MWe				
1966				
Jan.	Dresden 2	794 MWe	BWR/GE	Commonwealth Edison (IL)
Oct.	Dresden 3	794 MWe	BWR/GE	Commonwealth Edison (IL)
April	Robert E. Ginna	470 MWe	PWR/W	Rochester Gas and Electric
Oct.	Indian Point 2	873 MWe	PWR/W	Consolidated Edison of New York, Inc.
May	Millstone 1	660 MWe	BWR/GE	Northeast Utilities (CT)
Total: 5 reactors = 3,591 MWe				

Construction Permits
12

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1965				
	April	Nine Mile Point 1	620 MWe	BWR/GE	Niagara Mohawk Power
	Total: 1 reactor = 620 MWe				
	1964				
	May	Haddam Neck	582 MWe	PWR/W	Connecticut Yankee Atomic Power
	Dec.	Oyster Creek	650 MWe	BWR/GE	Jersey Central Power & Light
	March	San Onofre 1	436 MWe	PWR/W	Southern California Edison
	Total: 3 reactors = 1,668 MWe				
	1963				
	—	Hanford-N	860 MWe	GR/GE	DOE & Washington Public Power Supply System
	March	LaCrosse	50 MWe	BWR/AC	Dairyland Power Coop. (WI)
	Total: 2 reactors = 910 MWe				
	1962				
retired '74	Feb.	Peach Bottom 1	40 MWe	HTGR/GA	Philadelphia Electric
	Total: 1 reactor = 40 MWe (Net total: 0)				
	1961				
	none				
	1960				
	May	Big Rock Point	63 MWe	BWR/GE	Consumers Power (MI)
retired '68	July	BONUS	17 MWe	BWR/CE	DOE & Puerto Rico Water Resources
retired '67	May	CVTR	17 MWe	HWR/W	Carolinas-Virginia Nuclear Power Assoc. (SC)
retired '64	July	Hallam	75 MWe	SGR/AI	DOE & Consumers Public Power District (NE)
retired '83	Nov.	Humboldt Bay	65 MWe	BWR/GE	Pacific Gas & Electric (CA)
retired '67	May	Pathfinder	59 MWe	BWR/AC	Northern States Power (SD)
retired '66	Jan.	Piqua	11 MWe	OMR/AI	DOE & City of Piqua, Ohio
	Total: 7 reactors = 307 MWe (Net total: 1 reactor = 17 MWe)				
	1959				
retired '68	Dec.	Elk River	22 MWe	BWR/AC	DOE & Rural Cooperative Power Assoc. (MN)
	Total: 1 reactor = 22 MWe (Net total: 0)				
	1958				
	none				
	1957				
	Nov.	Yankee Rowe	175 MWe	PWR/W	Yankee Atomic Electric (MA)
	Total: 1 reactor = 175 MWe				
	1956				
retired '84	May	Dresden 1	207 MWe	BWR/GE	Commonwealth Edison (IL)
retired '72	Aug	Enrico Fermi 1	61 MWe	FBR/PRDC	Power Reactor Development (MI)
retired '80	May	Indian Point 1	265 MWe	PWR/B&W	Consolidated Edison of New York, Inc.
	Total: 3 reactors = 533 MWe (Net total: 0)				
	1955				
retired '82	—	Shippingport	60 MWe	LWBR/W	DOE & Duquesne Light (PA)
	Total: 1 reactor = 60 MWe (Net total: 0)				

LOW POWER OPERATING LICENSES ISSUED

	Unit	Net MWe	Type/Mfr.	Operating Utility
1985				
April	Diablo Canyon 2	1,106	PWR/W	Pacific Gas & Electric
March	Fermi 2	1,100	BWR/GE	Detroit Edison
Nov.	Millstone 3	1,150	PWR/W	Northeast Utilities
Dec.	Palo Verde 2	1,270	PWR/CE	Arizona Public Service
Aug.	River Bend 1	940	BWR/GE	Gulf States Utilities
July	Shoreham[a]	809	BWR/GW	Long Island Lighting
March	Wolf Creek	1,150	PWR/W	Kansas Gas & Electric
Total: 7 reactors = 7,525 MWe				
1984				
Oct.	Byron 1	1,120	PWR/W	Commonwealth Edison (IL)
June	Callaway 1	1,150	PWR/W	Union Electric (MO)
Dec.	Catawba 1	1,145	PWR/W	Duke Power (SC)
Oct.	Limerick 1	1,055	BWR/GE	Philadelphia Electric
Dec.	Palo Verde 1	1,270	PWR/CE	Arizona Public Service
March	Susquehanna 2	1,050	BWR/GE	Pennsylvania Power & Light
Dec.	Waterford 3	1,104	PWR/CE	Louisiana Power & Light
Total: 7 reactors = ~~7,991~~ MWe				
1983				
Dec.	LaSalle 2	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
March	William McGuire 2	1,180 MWe	PWR/W	Duke Power (NC)
April	St. Lucie 2	786 MWe	PWR/CE	Florida Power & Light
Dec.	WPPSS 2	1,100 MWe	BWR/GE	Washington Public Power Supply System
Total: 4 reactors = 4,144 MWe				
1982				
June	Grand Gulf 1	1,250 MWe	BWR/GE	Mississippi Power & Light
April	LaSalle 1	1,078 MWe	BWR/GE	Commonwealth Edison (IL)
Feb.	San Onofre 2	1,100 MWe	PWR/CE	Southern California Edison
Nov.	San Onofre 3	1,100 MWe	PWR/CE	Southern California Edison
Aug.	Summer 1	900 MWe	PWR/W	South Carolina Electric & Gas
July	Susquehanna 1	1,050 MWe	BWR/GE	Pennsylvania Power & Light
Total: 6 reactors = 6,478 MWe				
1981				
Sept.	Diablo Canyon 1	1,084 MWe	PWR/W	Pacific Gas and Electric (CA)
Jan.	William McGuire 1	1,180 MWe	PWR/W	Duke Power (NC)
June	Sequoyah 2	1,148 MWe	PWR/W	Tennessee Valley Authority
Total: 3 reactors = 3,412 MWe				
1980				
Oct.	Joseph M. Farley 2	860 MWe	PWR/W	Alabama Power
April	North Anna 2	850 MWe	PWR/W	Virginia Electric and Power
April	Salem 2	1,115 MWe	PWR/W	Public Service Electric and Gas (NJ)
Feb.	Sequoyah 1	1,148 MWe	PWR/W	Tennessee Valley Authority
Total: 4 reactors = 4,013 MWe				
1979				
none				
1978				
Sept.	Arkansas Nuclear One-2	912 MWe	PWR/CE	Arkansas Power & Light
June	Edwin I. Hatch 2	790 MWe	BWR/GE	Georgia Power
Feb.	Three Mile Island 2[b]	906 MWe	PWR/B&W	Metropolitan Edison (PA)
Total: 3 reactors = 2,608 MWe				
1977				
Dec.	Donald C. Cook 2	1,100 MWe	PWR/W	Indiana & Michigan Electric (MI)
April	Davis-Besse 1	890 MWe	PWR/B&W	Toledo Edison
June	Joseph M. Farley 1	860 MWe	PWR/W	Alabama Power
Nov.	North Anna 1	877 MWe	PWR/W	Virginia Electric and Power
Total: 4 reactors = 3,727 MWe				

[a]Received limited low power operating license 12/7/84 and nonrestricted low power operating license 7/3/85.
[b]Shut down since 3/28/79 accident.

	Unit	Net MWe	Type/Mfr.	Operating Utility
1976				
Jan.	Beaver Valley 1	833 MWe	PWR/W	Duquesne Light (PA)
July	Browns Ferry 3	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
Sept.	Brunswick 1	790 MWe	BWR/GE	Carolina Power & Light (NC)
Aug.	Calvert Cliffs 2	845 MWe	PWR/CE	Baltimore Gas & Electric
Dec.	Crystal River 3	880 MWe	PWR/B&W	Florida Power
March	St. Lucie 1	822 MWe	PWR/CE	Florida Power & Light
Aug	Salem 1	1,090 MWe	PWR/W	Public Service Electric and Gas (NJ)
Total: 7 reactors = 6,327 MWe				
1975				
Dec.	Indian Point 3	965 MWe	PWR/W	New York Power Authority
Sept.	Millstone 2	869 MWe	PWR/CE	Northeast Utilities (CT)
Nov.	Trojan	1,130 MWe	PWR/W	Portland General Electric
Total: 3 reactors = 2,964 MWe				
1974				
May	Arkansas Nuclear One-1	850 MWe	PWR/B&W	Arkansas Power & Light
June	Browns Ferry 2	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
Dec.	Brunswick 2	790 MWe	BWR/GE	Carolina Power & Light (NC)
July	Calvert Cliffs 1	845 MWe	PWR/CE	Baltimore Gas & Electric
Oct.	Donald C. Cook 1	1,030 MWe	PWR/W	Indiana & Michigan Electric (MI)
Jan.	Cooper	778 MWe	BWR/GE	Nebraska Public Power District
Feb.	Duane Arnold	538 MWe	BWR/GE	Iowa Electric Light and Power
Oct.	James A. Fitzpatrick	821 MWe	BWR/GE	New York Power Authority
Aug.	Edwin I. Hatch 1	786 MWe	BWR/GE	Georgia Power
July	Oconee 3	860 MWe	PWR/B&W	Duke Power (SC)
July	Peach Bottom 3	1,065 MWe	BWR/GE	Philadelphia Electric
Oct.	Prairie Island 2	530 MWe	PWR/W	Northern States Power (MN)
Aug.	Rancho Seco 1	918 MWe	PWR/B&W	Sacramento Municipal Utility District
April	Three Mile Island 1	819 MWe	PWR/B&W	Metropolitan Edison (PA)
Total: 14 reactors = 11,697 MWe				
1973				
June	Browns Ferry 1	1,067 MWe	BWR/GE	Tennessee Valley Authority (AL)
May	Fort Calhoun 1	486 MWe	PWR/CE	Omaha Public Power District
Dec.	Fort St. Vrain	330 MWe	HTGR/GA	Public Service of Colorado
Dec.	Kewaunee	535 MWe	PWR/W	Wisconsin Public Service
Feb.	Oconee 1	860 MWe	PWR/B&W	Duke Power (SC)
Oct.	Oconee 2	860 MWe	PWR/B&W	Duke Power (SC)
Aug.	Peach Bottom 2	1,065 MWe	BWR/GE	Philadelphia Electric
Aug	Prairie Island 1	530 MWe	PWR/W	Northern States Power (MN)
Jan.	Surry 2	775 MWe	PWR/W	Virginia Electric and Power
April	Turkey Point 4	666 MWe	PWR/W	Florida Power & Light
April	Zion 1	1,040 MWe	PWR/W	Commonwealth Edison (IL)
Nov.	Zion 2	1,040 MWe	PWR/W	Commonwealth Edison (IL)
Total: 12 reactors = 9,254 MWe				
1972				
Sept.	Maine Yankee	825 MWe	PWR/CE	Maine Yankee Atomic Power
June	Pilgrim 1	670 MWe	BWR/GE	Boston Edison
March	Quad Cities 2	789 MWe	BWR/GE	Commonwealth Edison (IL)
May	Surry 1	775 MWe	PWR/W	Virginia Electric and Power
July	Turkey Point 3	666 MWe	PWR/W	Florida Power & Light
March	Vermont Yankee	514 MWe	BWR/GE	Vermont Yankee Nuclear Power
Total: 6 reactors = 4,239 MWe				
1971				
Jan.	Dresden 3	794 MWe	BWR/GE	Commonwealth Edison (IL)
Oct.	Indian Point 2	873 MWe	PWR/W	Consolidated Edison of New York, Inc.
March	Palisades	757 MWe	PWR/CE	Consumers Power (MI)
Nov.	Point Beach 2	497 MWe	PWR/W	Wisconsin Electric Power (WI)
Sept.	Quad Cities 1	789 MWe	BWR/GE	Commonwealth Edison (IL)
Total: 5 reactors = 3,710 MWe				

		Unit	Net MWe	Type/Mfr.	Operating Utility
	1970				
	Oct.	Millstone 1	660 MWe	BWR/GE	Northeast Utilities (CT)
	Sept.	Monticello	545 MWe	BWR/GE	Northern States Power (MN)
	Oct.	Point Beach 1	497 MWe	PWR/W	Wisconsin Electric Power (WI)
	Aug.	H.B. Robinson 2	665 MWe	PWR/W	Carolina Power & Light (SC)
	Total: 4 reactors = 2,367 MWe				
	1969				
	Dec.	Dresden 2	794 MWe	BWR/GE	Commonwealth Edison (IL)
	Sept.	Robert E. Ginna	470 MWe	PWR/W	Rochester Gas and Electric
	Aug.	Nine Mile Point 1	620 MWe	BWR/GE	Niagara Mohawk Power
	April	Oyster Creek	650 MWe	BWR/GE	Jersey Central Power & Light
	Total: 4 reactors = 2,534 MWe				
	1968				
	none				
	1967				
	June	Haddam Neck	582 MWe	PWR/W	Connecticut Yankee Atomic Power
	July	LaCrosse	50 MWe	BWR/AC	Dairyland Power Coop. (WI)
	March	San Onofre 1	436 MWe	PWR/W	Southern California Edison
	Total: 3 reactors = 1,068 MWe				
	1966				
	—	Hanford-N	860 MWe	GR/GE	DOE & Washington Public Power Supply System
retired '74	Jan.	Peach Bottom 1	40 MWe	HTGR/GA	Philadelphia Electric
	Total: 2 reactors = 900 MWe (Net total: 1 reactor = 860 MWe)				
	1965				
	none				
	1964				
retired '68	April	BONUS	17 MWe	BWR/CE	DOE & Puerto Rico Water Resources
retired '67	March	Pathfinder	59 MWe	BWR/AC	Northern States Power (SD)
	Total: 2 reactors = 76 MWe (Net total: 0)				
	1963				
retired '72	May	Enrico Fermi 1	61 MWe	FBR/PRDC	Power Reactor Development (MI)
	Total: 1 reactor = 61 MWe (Net total: 0)				
	1962				
	Aug.	Big Rock Point	63 MWe	BWR/GE	Consumers Power (MI)
retired '67	Nov.	CVTR	17 MWe	HWR/W	Carolinas-Virginia Nuclear Power Assoc. (SC)
retired '68	Nov.	Elk River	22 MWe	BWR/AC	Rural Cooperative Power Assoc. (MN)
retired '64	Aug.	Hallam	75 MWe	SGR/AI	DOE & Consumers Public Power District (NE)
retired '83	Aug.	Humboldt Bay	65 MWe	BWR/GE	Pacific Gas & Electric (CA)
retired '80	March	Indian Point 1	265 MWe	PWR/B&W	Consolidated Edison of New York, Inc.
retired '66	Aug.	Piqua	11 MWe	OMR/AI	DOE & City of Piqua, Ohio
	Total: 7 reactors = 518 MWe (Net total: 1 reactor = 63 MWe)				
	1961				
	none				
	1960				
	July	Yankee Rowe	175 MWe	PWR/W	Yankee Atomic Electric (MA)
	Total: 1 reactor = 175 MWe				
	1959				
retired '84	Sept.	Dresden 1	207 MWe	BWR/GE	Commonwealth Edison (IL)
	Total: 1 reactor = 207 MWe (Net total: 0)				
	1958				
	none				
	1957				
retired '82	March	Shippingport[a]	60 MWe	LWBR/W	DOE & Duquesne Light (PA)
	Total: 1 reactor = 60 MWe (Net total: 0)				

[a]LWBR core replaced Shippingport's PWR core in 1977.

CANCELLATIONS ANNOUNCED

Unit	Net MWe	Type/Mfr.	Operating Utility
1985			
none			
1984			
Hartsville A-1 (C-44%)	1,233	BWR/GE	Tennessee Valley Authority
Hartsville A-2 (C-34%)	1,233	BWR/GE	Tennessee Valley Authority
Marble Hill 1 (C-60%)	1,130	PWR/W	Public Service Indiana
Marble Hill 2 (C-37%)	1,130	PWR/W	Public Service Indiana
River Bend 2 (C-0%)	934	BWR/GE	Gulf States Utilities (LA)
Yellow Creek 1 (C-35%)	1,285	PWR/CE	Tennessee Valley Authority
Yellow Creek 2 (C-3%)	1,285	PWR/CE	Tennessee Valley Authority
Zimmer 1 (C-97%)	810	BWR/GE	Cincinnati Gas & Electric
Total: 8 reactors = 9,040 MWe			
1983			
Cherokee 1 (C-17%)	1,280 MWe	PWR/CE	Duke Power (SC)
Clinton 2 (C-1%)	933 MWe	BWR/GE	Illinois Power
CRBRP (LWA < 1%)	375 MWe	LMFBR/W	U.S. Department of Energy (TN)
Shearon Harris 2 (C-4%)	900 MWe	PWR/W	Carolina Power & Light (NC)
Skagit 1 (O)	1,275 MWe	BWR/GE	Puget Sound Power and Light (WA)
Skagit 2 (O)	1,275 MWe	BWR/GE	Puget Sound Power and Light (WA)
Total: 6 reactors = 6,038 MWe			
1982			
Allens Creek 1 (O)	1,200 MWe	BWR/GE	Houston Lighting & Power
Black Fox 1 (LWA < 1%)	1,150 MWe	BWR/GE	Public Service of Oklahoma
Black Fox 2 (LWA < 1%)	1,150 MWe	BWR/GE	Public Service of Oklahoma
Cherokee 2 (C-0%)	1,280 MWe	PWR/CE	Duke Power (SC)
Cherokee 3 (C-0%)	1,280 MWe	PWR/CE	Duke Power (SC)
Hartsville B-1 (C-17%)	1,233 MWe	BWR/GE	Tennessee Valley Authority
Hartsville B-2 (C-7%)	1,233 MWe	BWR/GE	Tennessee Valley Authority
North Anna 3 (C-7%)	907 MWe	PWR/B&W	Virginia Electric and Power
Pebble Springs 1 (O)	1,260 MWe	PWR/B&W	Portland General Electric
Pebble Springs 2 (O)	1,260 MWe	PWR/B&W	Portland General Electric
Perkins 1 (O)	1,280 MWe	PWR/CE	Duke Power (NC)
Perkins 2 (O)	1,280 MWe	PWR/CE	Duke Power (NC)
Perkins 3 (O)	1,280 MWe	PWR/CE	Duke Power (NC)
Phipps Bend 1 (C-27%)	1,233 MWe	BWR/GE	Tennessee Valley Authority
Phipps Bend 2 (C-5%)	1,233 MWe	BWR/GE	Tennessee Valley Authority
Vandalia (O)	1,270 MWe	PWR/B&W	Iowa Power and Light
WPPS 4 (C-23%)	1,250 MWe	PWR/CE	Washington Public Power Supply System
WPPS 5 (C-16%)	1,240 MWe	PWR/CE	Washington Public Power Supply System
Total: 18 reactors = 22,019 MWe			
1981			
Bailly Nuclear 1 (C < 1%)	644 MWe	BWR/GE	Northern Indiana Public Service
Callaway 2 (C < 1%)	1,150 MWe	PWR/W	Union Electric (MO)
Shearon Harris 3 (C-1%)	900 MWe	PWR/W	Carolina Power & Light (NC)
Shearon Harris 4 (C-1%)	900 MWe	PWR/W	Carolina Power & Light (NC)
Hope Creek 2 (C-19%)	1,067 MWe	BWR/GE	Public Service Electric and Gas (NJ)
Pilgrim 2 (O)	1,150 MWe	PWR/CE	Boston Edison
Total: 6 reactors = 5,811 MWe			
1980			
Davis-Besse 2 (LWA-0%)	906 MWe	PWR/B&W	Toledo Edison
Davis-Besse 3 (LWA-0%)	906 MWe	PWR/B&W	Toledo Edison
Erie 1 (O)	1,260 MWe	PWR/B&W	Ohio Edison
Erie 2 (O)	1,260 MWe	PWR/B&W	Ohio Edison
Forked River 1 (C-5%)	1,168 MWe	PWR/CE	Jersey Central Power & Light
Greenwood 2 (O)	1,264 MWe	PWR/B&W	Detroit Edison
Greenwood 3 (O)	1,264 MWe	PWR/B&W	Detroit Edison
Haven 1 (O)	900 MWe	PWR/W	Wisconsin Electric Power
Jamesport 1 (C-0%)	1,150 MWe	PWR/W	Long Island Lighting
Jamesport 2 (C-0%)	1,150 MWe	PWR/W	Long Island Lighting
Montague 1 (O)	1,150 MWe	BWR/GE	Northeast Utilities (MA)
Montague 2 (O)	1,150 MWe	BWR/GE	Northeast Utilities (MA)
New Haven 1 (O)	1,250 MWe	PWR/CE	New York State Electric & Gas
New Haven 2 (O)	1,250 MWe	PWR/CE	New York State Electric & Gas
North Anna 4 (C-4%)	907 MWe	PWR/B&W	Virginia Electric and Power
Sterling (C-0%)	1,150 MWe	PWR/W	Rochester Gas and Electric
Total: 16 reactors = 18,085 MWe			

Unit	Net MWe	Type/Mfr.	Operating Utility
1979			
Greene County (O)	1,200 MWe	PWR/B&W	New York Power Authority
NEP-1 (O)	1,150 MWe	PWR/W	New England Power (RI)
NEP-2 (O)	1,150 MWe	PWR/W	New England Power (RI)
Palo Verde 4 (O)	1,270 MWe	PWR/CE	Arizona Public Service
Palo Verde 5 (O)	1,270 MWe	PWR/CE	Arizona Public Service
Tyrone 1 (C-0%)	1,100 MWe	PWR/W	Northern States Power (WI)
unit 1 (O)	1,168 MWe	BWR/GE	Pacific Gas and Electric (CA)
unit 2 (O)	1,168 MWe	BWR/GE	Pacific Gas and Electric (CA)
Total: 8 reactors = 9,476 MWe			
1978			
Atlantic 1 (O)	1,150 MWe	PWR/W	Public Service Electric and Gas (offshore, NJ)
Atlantic 2 (O)	1,150 MWe	PWR/W	Public Service Electric and Gas (offshore, NJ)
Blue Hills 1 (O)	950 MWe	PWR/CE	Gulf States Utilities (TX)
Blue Hills 2 (O)	950 MWe	PWR/CE	Gulf States Utilities (TX)
Haven 2 (O)	900 MWe	PWR/W	Wisconsin Electric Power
Islote (O)	583 MWe	PWR/W	Puerto Rico Water Resources Authority
S.R. 1 (O)	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
S.R. 2 (O)	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
Sundesert 1 (O)	950 MWe	PWR/W	San Diego Gas and Electric
Sundesert 2 (O)	950 MWe	PWR/W	San Diego Gas and Electric
unit 1 (O)	1,150 MWe	PWR/W	Public Service Electric and Gas (offshore, NJ)
unit 2 (O)	1,150 MWe	PWR/W	Public Service Electric and Gas (offshore, NJ)
Wm. H. Zimmer 2 (O)	1,150 MWe	BWR/GE	Cincinnati Gas & Electric
Total: 13 reactors = 13,333 MWe			
1977			
Alan Barton 1 (O)	1,170 MWe	BWR/GE	Alabama Power
Alan Barton 2 (O)	1,170 MWe	BWR/GE	Alabama Power
Douglas Point 1 (O)	1,178 MWe	BWR/GE	Potomac Electric Power (MD)
Ft. Calhoun 2 (O)	1,150 MWe	PWR/W	Omaha Public Power District
South Dade 1 (O)	1,140 MWe	PWR/W	Florida Power & Light
South Dade 2 (O)	1,140 MWe	PWR/W	Florida Power & Light
Surry 3 (C 0%)	882 MWe	PWR/B&W	Virginia Electric and Power
Surry 4 (C 0%)	882 MWe	PWR/B&W	Virginia Electric and Power
unit 1 (O)	1,150 MWe	PWR/W	Central Maine Power
Total: 9 reactors = 9,862 MWe			
1976			
Allens Creek 2 (O)	1,150 MWe	BWR/GE	Houston Lighting & Power
Douglas Point 2 (O)	1,178 MWe	BWR/GE	Potomac Electric Power (MD)
Total: 2 reactors = 2,328 MWe			
1975			
Alan Barton 3 (O)	1,170 MWe	BWR/GE	Alabama Power
Alan Barton 4 (O)	1,170 MWe	BWR/GE	Alabama Power
Enrico Fermi 3 (O)	1,171 MWe	BWR/GE	Detroit Edison
Fulton 1 (O)	1,160 MWe	HTGR/GA	Philadelphia Electric
Fulton 2 (O)	1,160 MWe	HTGR/GA	Philadelphia Electric
St. Rosalie 1 (O)	1,160 MWe	HTGR/GA	Louisiana Power & Light
St. Rosalie 2 (O)	1,160 MWe	HTGR/GA	Louisiana Power & Light
Summit 1 (LWA 0%)	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
Summit 2 (LWA 0%)	770 MWe	HTGR/GA	Delmarva Power & Light (DE)
unit 1 (O)	1,300 MWe	PWR/CE	Florida Power
unit 2 (O)	1,300 MWe	PWR/CE	Florida Power
Total: 11 reactors = 12,291 MWe			
1974			
Eastern Desert 1 (O)	770 MWe	HTGR/GA	Southern California Edison
Eastern Desert 2 (O)	770 MWe	HTGR/GA	Southern California Edison
Quanicassee 1 (O)	1,150 MWe	PWR/W	Consumers Power (MI)
Quanicassee 2 (O)	1,150 MWe	PWR/W	Consumers Power (MI)
S.R. 3 (O)	1,150 MWe	PWR/B&W	Carolina Power & Light (NC)
Tyrone 2 (O)	1,100 MWe	PWR/W	Northern States Power (WI)
Alvin W. Vogtle 3 (C 0%)	1,100 MWe	PWR/W	Georgia Power
Alvin W. Vogtle 4 (C 0%)	1,100 MWe	PWR/W	Georgia Power
Total: 8 reactors = 8,290 MWe			
1973			
none			

Cancellations
18

Unit	Net MWe	Type/Mfr.	Operating Utility
1972			
Bell (O)	838 MWe	BWR/GE	New York State Electric & Gas
Crystal River 4 (O)	910 MWe	PWR/B&W	Florida Power
Nuclear 4 (O)	1,115 MWe	BWR/GE	Consolidated Edison of New York, Inc.
Nuclear 5 (O)	1,115 MWe	BWR/GE	Consolidated Edison of New York, Inc.
Perryman 1 (O)	880 MWe	PWR/CE	Baltimore Gas and Electric
Perryman 2 (O)	880 MWe	PWR/CE	Baltimore Gas and Electric

Total: 6 reactors = 5,738 MWe

RETIREMENTS ANNOUNCED

Unit	Net MWe	Type/Mfr.	Operating Utility
1985			
none			
1984			
Dresden 1 ('59-'78)	207	BWR/GE	Commonwealth Edison (IL)
Total: 1 reactor = 207 MWe			
1983			
Humboldt Bay ('62-'76)	65 MWe	BWR/GE	Pacific Gas and Electric (CA)
Total: 1 reactor = 65 MWe			
1982			
Shippingport ('57-'82)	60 MWe	LWBR/W	DOE & Duquesne Light (PA)
Total: 1 reactor = 60 MWe			
1981			
none			
1980			
Indian Point 1 ('62-'74)	265 MWe	PWR/B&W	Consolidated Edison of New York, Inc.
Total: 1 reactor = 265 MWe			
1979			
none			
1978			
none			
1977			
none			
1976			
none			
1975			
none			
1974			
Peach Bottom 1 ('66-'74)	40 MWe	HTGR/GA	Philadelphia Electric
Total: 1 reactor = 40 MWe			
1973			
none			
1972			
Enrico Fermi 1 ('63-'72)	61 MWe	FBR/PRDC	Power Reactor Development (MI)
Total: 1 reactor = 61 MWe			
1971			
none			
1970			
none			
1969			
none			
1968			
BONUS ('64-'68)	17 MWe	BWR/CE	DOE & Puerto Rico Water Resources
Elk River ('62-'68)	22 MWe	BWR/AC	Rural Cooperative Power Assoc. (MN)
Total: 2 reactors = 39 MWe			
1967			
CVTR ('62-'67)	17 MWe	HWR/W	Carolinas-Virginia Nuclear Power Assoc. (SC)
Pathfinder ('64-'67)	59 MWe	BWR/AC	Northern States Power (SD)
Total: 2 reactors = 76 MWe			
1966			
Piqua ('62-'66)	11 MWe	OMR/AI	DOE & City of Piqua, Ohio
Total: 1 reactors = 11 MWe			
1965			
none			
1964			
Hallam ('62-'64)	75 MWe	SGR/AI	DOE & Consumers Public Power District (NE)
Total: 1 reactor = 75 MWe			

HISTORICAL PROFILE OF U.S. NUCLEAR POWER DEVELOPMENT — 1953 TO 1985

End of Year	Operating Licenses Issued				Construction Permits Issued				Limited Work Authorizations Issued						Orders Placed				Cancellations Announced		Retirements Announced		Total Commitments	
	Annually	MWe	Net Total	MWe	Annually	MWe	Net Total	MWe	Annually	MWe	Rec'd CP's	MWe	Net Total	MWe	Annually	MWe	Net Total	MWe	Annually	MWe	Annually	MWe	Annually	MWe
1953																								
1954															1	60	1	60					1	60
1955					1	60	1	60							0	0	1	60					1	60
1956					3	533	4	593							3	533	3	533					4	593
1957	1	60	1	60	1	175	4	708							1	175	1	175					5	768
1958	0	0	1	60	0	0	4	708							2	134	2	134					7	902
1959	1	207	2	267	1	22	4	523							3	127	5	261					10	1,029
1960	1	175	3	442	7	307	10	855							3	91	7	330					13	1,120
1961	0	0	3	442	0	0	10	855							1	17	1	40					14	1,137
1962	7	518	10	960	1	40	4	177							0	0	1	40					14	1,137
1963	1	61	11	1,021	2	910	5	1,026							2	632	2	632					16	1,769
1964	2	76	12	1,022	3	1,668	6	2,616							4	2,566	4	2,266					20	4,335
1965	0	0	12	1,022	1	620	7	3,238							0	0	1	620			1	75	19	4,260
1966	2	900	13	1,911	5	3,591	10	5,929							7	4,463	7	4,463					26	8,723
1967	3	1,068	14	2,903	14	10,602	21	15,463							20	16,363	22	17,235			1	11	45	25,075
1968	0	0	12	2,864	23	18,764	44	34,227							31	26,447	39	33,080			2	76	74	51,446
1969	4	2,534	16	5,398	7	6,477	47	38,170							16	15,063	32	29,379			2	39	88	66,470
1970	4	2,367	20	7,765	10	8,865	53	44,668							7	7,332	32	30,234					95	73,802
1971	5	3,710	25	11,475	4	3,787	52	44,745							14	14,275	36	35,644					109	88,077
1972	6	4,239	30	15,653	8	6,604	54	47,110							21	20,876	53	52,733					130	108,953
1973	12	9,254	42	24,907	14	15,184	56	53,040							38	41,526	77	81,917	6 orders	5,738	1	61	161	144,880
1974	14	11,697	55	36,564	23	24,262	63	63,405	20	21,534	14	15,644	6	5,890	41	46,827	104	113,560					202	191,507
1975	3	2,964	58	39,528	9	10,520	69	70,961	21	22,062	9	10,520	16	16,892	26	30,931	95	108,249	6 orders 2 CP's	6,090 2,200	1	40	219	214,108
1976	7	6,327	65	45,855	9	10,276	71	74,910	7	8,772	4	4,166	19	20,498	4	4,180	69	79,616	9 orders 2 LWA's	10,751 1,540			212	205,997
1977	4	3,727	69	49,582	15	17,236	80	86,855	6	7,206	12	13,836	13	13,868	3	3,790	58	66,196	2 orders	2,328			213	207,459
1978	3	2,606	72	52,190	13	14,626	90	98,673	4	4,870	13	14,626	4	4,112	4	5,040	46	52,532	7 orders 2 CP's	8,098 1,764			208	202,837
1979	0	0	72	52,190	2	2,300	91	99,873	0	0	0	0	4	4,112	2	2,240	31	36,569	13 orders	13,333			197	191,544
1980	4	4,013	76	56,938	0	0	82	90,335	0	0	0	0	2	2,300	0	0	22	25,893	7 orders 1 CP	8,376 1,100			189	182,068
1981	3	3,412	78	59,350	0	0	74	82,262	0	0	0	0	2	2,300	0	0	13	15,145	9 orders 2 LWA's 5 CP's	10,748 1,812 5,525	1	265	172	163,718
1982	6	6,478	83	65,768	0	0	59	64,895	0	0	0	0	0	0	0	0	5	5,165	1 order 5 CP's	1,150 4,661			166	157,907
1983	4	4,144	86	69,847	0	0	52	57,638	1	375	0	0	0	0	0	0	2	2,240	7 orders 2 LWA's 9 CP's	8,830 2,300 10,889	1	60	147	135,828
1984	7	7,881	82	77,595	0	0	37	40,651	0	0	0	0	0	0	0	0	2	2,240	2 orders 1 LWA 3 CP's	2,550 375 3,113	1	65	140	129,725
1985	7	7,525	99	84,974	0	0	30	30,170	0	0	0	0	0	0	0	0	2	2,240	6 CP's	9,040	1	207	131	120,486
																							131	120,384

Net Total indicates balance remaining in a given status.

	0-½	½-1½	1½-2½	2½-3½	3½-4½	4½-5½	5½-6½	6½-7½	7½-8½	8½-9½	9½-10½	10½-11½	11½-12½	12½-13½	13½-14½	14½-15½	15½-16½	16½-17½	17½-18½	18½-19½	19½-20½	20½-21½	21½-22½	22½-23½	23½-24½	24½-25½	25½-26½	26½-27½	27½-28½	
1957	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1[12]	—	—	—	
1958	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—		
1959	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1[11]	—			
1960	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
1961	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—					
1962	7	7	7[1]	6	6[2]	5[3]	4[4]	3	3	3	3	3	3	3	3	3	3	3	3[7]	2	2	2[11]	1	1						
1963	1	1	1	1	1	1	1	1	1	1[8]	—	—	—	—	—	—	—	—	—	—	—	—	—							
1964	2	2	2	2[2]	1[3]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—								
1965	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—									
1966	2	2	2	2	2	2	2	2	2[7]	1	1	1	1	1	1	1	1	1	1	1										
1967	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3											
1968	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—												
1969	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4													
1970	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4														
1971	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5															
1972	6	6	6	6	6	6	6	6	6	6	6	6	6	6																
1973	12	12	12	12	12	12	12	12	12	12	12	12	12																	
1974	14	14	14	14	14	14	14	14	14	14	14	14																		
1975	3	3	3	3	3	3	3	3	3	3	3																			
1976	7	7	7	7	7	7	7	7	7	7																				
1977	4	4	4	4	4	4	4	4	4																					
1978	3	3	3	3	3	3	3	3																						
1979	—	—	—	—	—	—	—																							
1980	4	4	4	4	4	4																								
1981	3	3	3	3	3																									
1982	6	6	6	6																										
1983	4	4	4																											
1984	7	7																												
1985	7																													
Total Units Exposed to Retirement	111	104	97	92	85	80	75	74	71	66	58	55	41	29	23	18	14	10	10	6	5	5	4	4	3	3	—	—	—	
Total Units Retired in Interval	—	—	1	1	2	1	1	—	1	1	—	—	—	—	—	—	—	—	1	—	—	1	—	—	—	2	—	—	—	
Total Units Surviving Through Interval	111	104	96	91	83	79	74	74	70	65	58	55	41	29	23	18	14	10	9	6	5	4	4	4	3	1	—	—	—	
Total Mile Exposed to Retirement	85 458	78 433	71 534	66 370	59 783	56 343	52 313	52 191	44 683	45 916	38 528	36 551	34 867	15 613	11 374	7 664	5 241	2 763	2 263	1 430	570	570	505	505	441	441	—	—	—	
Total Mile Retired in Interval	—	—	75	59	28	12	22	—	40	61	—	—	—	—	—	—	—	—	965	—	—	65	—	—	—	267	—	—	—	
Total Mile Surviving Through Interval	85 458	78 433	70 464	66 [illegible]	54 155	56 376	52 241	52 291	49 643	45 [illegible]	38 528	36 554	34 867	15 613	11 374	7 664	5 257	2 763	2 498	1 430	570	605	505	505	441	171	—	—	—	

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	UNIT	MWe	LIFE	AGE
1	HALLAM	75	1962-1964	2
2	PATHFINDER	59	1964-1967	3
3	BONUS	17	1964-1968	4
4	PIQUA	11	1962-1966	4
5	CVTR	17	1962-1967	5
6	ELK RIVER	22	1962-1968	6
7	PEACH BOTTOM 1	40	1966-1974	8
8	FERMI 1	61	1963-1972	9
9	INDIAN POINT 1	265	1962-1980	18
10	HUMBOLDT BAY	65	1962-1983	21
11	DRESDEN 1	207	1959-1989	25
12	SHIPPINGPORT	60	1957-1982	25

EXHIBIT ____

Schedule (DJL-5)

Louisiana Power & Light Company
Louisiana PSC Docket No. U-16945

Jefferson Parish Second Data Request

Question No. 8:

Please provide a copy of any written report prepared by MSU or LP&L which describes the current status of the nuclear generating facility referred to as Grand Gulf II ("GG II").

Response:

LP&L objects to Data Request No. 8 for the reason that the status of Grand Gulf II is not a matter within the jurisdiction of the LPSC, and no element of LP&L's rate application is related in any way to Grand Gulf II. Moreover, LP&L has no authority over reports prepared by Middle South Utilities, Inc.

Louisiana Power & Light Company
Louisiana PSC Docket No. U-16945

Jefferson Parish Second Data Request

Question No. 9:

Please provide a copy of all guidelines and assumptions made or established by LP&L or MSU or the GG II Task Force which are to be utilized in the determination of whether to continue construction or cancel GG II.

Response:

See Answer to Data Request No. 8.

Louisiana Power & Light Company
Louisiana PSC Docket No. U-16945

Jefferson Parish Second Data Request

Question No. 10:

Explain in detail the types of studies and investigations made or to be made before a determination will be made with respect to the continuing construction or cancellation of GG II and provide a copy of any documents that are related to or produced by such studies or investigations.

Response:

See Answer to Data Request No. 8.

EXHIBIT ____

Schedule (DJL-6)

LP&L DR00740
TB&A #589

QUESTION: Report or analysis supporting the St. Rosalie cancellation.

RESPONSE: Attached is the LP&L news release of June 25, 1975 announcing the cancellation of St. Rosalie. Additional information associated with St. Rosalie was originally supplied with TB&A Document Request Numbers 512 and 531.

NEWS Release

LOUISIANA POWER & LIGHT • PUBLIC RELATIONS DEPARTMENT, 142 DELARONDE ST., NEW ORLEANS, LA. 70174 • TELEPHONE (504) 366-2345

June 25, 1975

Louisiana Power & Light Company announced today it has cancelled plans to build two nuclear-fueled generating units at its St. Rosalie Station at Alliance in Plaquemines Parish.

E. A. Rodrigue, LP&L president, in announcing the cancellation stated that doubling of the cost of constructing the plant from $1.2 billion to approximately $2.3 billion and the inability of LP&L to finance this higher cost were the principal reasons for the action taken.

"Much of the added cost can be laid to the 'no-growth' environmentalists and and the bureaucratic red tape of those Federal agencies involved in regulating the building of nuclear facilities," Rodrigue said. He gave as an example the added cost involved in going ahead with LP&L's first nuclear unit at its Waterford Station. Announced in September, 1970, at an estimated cost of $230 million, he stated that the rulings and requirements of the Atomic Energy Commission and the Justice Department were largely responsible for the delays in starting construction. These delays coupled with the increased requirements of the Environmental Protection Agency have tripled the cost of that plant to an estimated $700 million and have resulted in a four-year delay in time schedule.

"Unfortunately," Rodrigue pointed out, "such cost increases must eventually be made up in the amount our customers pay for their electricity."

In addition to LP&L's announcement of the St. Rosalie cancellation, other Middle South Utilities companies simultaneously announced changes in their expansion plans.

...more

Mississippi Power & Light Company and Middle South Energy, Inc. will delay the construction of the second nuclear unit at its Port Gibson plant from 1982 to 1984. Two coal-fueled units for Arkansas Power & Light Company originally scheduled for 1978 and 1979 operation have been delayed to 1979 and 1981 operation dates.

These cancellations and deferrals of announced generation and related additions will reduce the Middle South System's overall construction budget by approximately $650 million in the 1975-1978 period, according to Rodrigue.

Rodrigue pointed out that Middle South System's construction program at the reduced levels will raise a question, for the first time in the history of the Middle South System, of its ability to meet all the electric energy requirements of its customers in the future. Under the revised construction program, the Middle South System reserve generating capacity margin, which its engineers believe should be maintained at 16 percent, will be decreased to 12 percent by 1979. A reserve margin at this lower level will result in a substantial lessening of System reliability.

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EXHIBIT ____

Schedule (DJL-7)

(A) IN GENERAL.—Except as provided in this section, section 204, and section 211(d), the amendments made by section 201 shall apply to property placed in service after December 31, 1986, in taxable years ending after such date.

(B) ELECTION TO HAVE AMENDMENTS MADE BY SECTION 201 APPLY.—A taxpayer may elect (at such time and in such manner as the Secretary of the Treasury or his delegate may prescribe) to have the amendments made by section 201 apply to any property placed in service after July 31, 1986, and before January 1, 1987.

(2) SECTION 203.—The amendments made by section 203 shall apply to property placed in service after December 31, 1986, in taxable years ending after such date.

(3) GENERAL TRANSITIONAL RULE.—

(A) IN GENERAL.—The amendments made by section 201 shall not apply to—

(i) any property which is constructed, reconstructed, or acquired by the taxpayer pursuant to a written contract which was binding on March 1, 1986,

(ii) property which is constructed or reconstructed by the taxpayer if—

(I) the lesser of (aa) $1,000,000, or (bb) 5 percent of the cost of such property has been incurred or committed by March 1, 1986, and

(II) the construction or reconstruction of such property began by such date, or

(iii) an equipped building or plant facility if construction has commenced as of March 1, 1986, pursuant to a written specific plan and more than one-half of the cost of such equipped building or facility has been incurred or committed by such date.

(B) REQUIREMENT THAT CERTAIN PROPERTY BE PLACED IN SERVICE BEFORE CERTAIN DATE.—

(i) IN GENERAL.—Paragraph (1) and section 204(a) (other than paragraph (3) or (12) thereof) shall not apply to any property unless such property has a class life of at least 7 years and is placed in service before the applicable date determined under the following table:

In the case of property with a class life of	The applicable date is:
At least 7 but less than 20 years	January 1, 1989
20 years or more	January 1, 1991.

(ii) RESIDENTIAL RENTAL AND NONRESIDENTIAL REAL PROPERTY.—In the case of residential rental property and nonresidential real property, the applicable date is January 1, 1991.

(C) CLASS LIVES.—For purposes of subparagraph (A)—

(i) the class life of property to which section 168(g)(3)(B) of the Internal Revenue Code of 1986 (as added by section 201) shall be the class life in effect on January 1, 1986, except that computer-based telephone central office switching equipment described in section 168(e)(3)(B)(vii) of such Code shall be treated as having a class life of 9 years,

(ii) property described in section 204(a) shall be treated as having a class life of 20 years, and

(iii) property with no class life shall be treated as having a class life of 12 years.

(D) SUBSTITUTION OF APPLICABLE DATES.—If any provision of this Act substitutes a date for an applicable date, this paragraph shall be applied by using such date.

(3) PROPERTY QUALIFIES IF SOLD AND LEASED BACK BY 3 MONTHS.—Property shall be treated as meeting the requirements of paragraphs (1) and (2) of section 204(a) with respect to any taxpayer if such property is acquired by the taxpayer from a person—

(A) in whose hands such property met the requirements of paragraphs (1) and (2) of section 204(a), or

(B) who placed the property in service before January 1, 1987,

and such property is leased back by the taxpayer to such person not later than the earlier of the applicable date under paragraph (1) or the day which is 3 months after such property was placed in service.

(4) PLANT FACILITY.—For purposes of paragraph (1), the term "plant facility" means a facility which does not include any building for with respect to which buildings constitute an insignificant portion) and which is—

(A) a self-contained single operating unit or processing operation,

(B) located on a single site, and

(C) identified as a single unitary project as of March 1, 1986.

(5) PROPERTY FINANCED WITH TAX-EXEMPT BONDS.—

(A) IN GENERAL.—Subparagraph (C) of section 168(g)(1) of the Internal Revenue Code of 1986 (as added by this Act) shall apply to property placed in service after December 31, 1986, in taxable years ending after such date, to the extent such property is financed by the proceeds of an obligation (including a refunding obligation) issued after March 1, 1986.

(B) EXCEPTIONS.—

(i) CONSTRUCTION OR BINDING AGREEMENTS.—Subparagraph (C) of section 168(g)(1) of such Code (as so added) shall not apply to obligations with respect to a facility—

(I) the original use of which commences with the taxpayer, and the construction, reconstruction, or rehabilitation of which began before March 2, 1986, and was completed on or after such date,

(II) with respect to which a binding contract to incur significant expenditures for construction, reconstruction, or rehabilitation was entered into before March 2, 1986, and some of such expenditures are incurred on or after such date, or

(III) acquired on or after March 2, 1986, pursuant to a binding contract entered into before such date, and

(ii) described in an inducement resolution or other comparable preliminary approval adopted by the issuing authority (or by a voter referendum) before March 2, 1986.

(C) REFUNDING.—

(i) IN GENERAL.—Except as provided in clause (ii), in the case of property placed in service after December 31, 1986, which is financed by the proceeds of an obligation which is issued solely to refund another obligation which was issued before March 2, 1986, subparagraph (C) of section 168(g)(1) of such Code (as so added) shall apply only with respect to an amount equal to the basis in such property which has not been recovered before the date such refunded obligation is issued.

(ii) SIGNIFICANT EXPENDITURES.—In the case of facilities the original use of which commences with the taxpayer and with respect to which significant expenditures are made before January 1, 1987, subparagraph (C) of section 168(g)(1) of such Code (as so added) shall not apply with respect to such facilities to the extent such facilities are financed by the proceeds of an obligation issued solely to refund another obligation which was issued before March 2, 1986.

(C) FACILITIES.—In the case of an inducement resolution or other comparable preliminary approval adopted by an issuing authority before March 2, 1986, for purposes of subparagraphs (A) and (B)(ii) with respect to obligations described in such resolution, the term "facilities" means the facilities described in such resolution.

(D) SIGNIFICANT EXPENDITURES.—For purposes of this paragraph, the term "significant expenditures" means expenditures greater than 10 percent of the reasonably anticipated cost of the construction, reconstruction, or rehabilitation of the facility involved.

(d) MID-QUARTER CONVENTION.—In the case of any taxable year in which property to which the amendments made by section 201 do not apply is placed in service, such property shall be taken into account in determining whether section 168(d)(3) of the Internal Revenue Code of 1986 (as added by section 201) applies for such taxable year to property to which such amendments apply.

(e) NORMALIZATION REQUIREMENTS.—

(1) IN GENERAL.—A normalization method of accounting shall not be treated as being used with respect to any public utility property for purposes of section 167 or 168 of the Internal Revenue Code of 1986 if the taxpayer, in computing its cost of service for rate-making purposes and reflecting operating results in its regulated books of account, reduces the excess tax reserve more rapidly or to a greater extent than such reserve would be reduced under the average rate assumption method.

(2) DEFINITIONS.—For purposes of this subsection—

(A) EXCESS TAX RESERVE.—The term "excess tax reserve" means the excess of—

(i) the reserve for deferred taxes (as described in section 167(l)(3)(G)(ii) or 168(e)(3)(B)(ii) of the Internal Revenue Code of 1954 as in effect on the day before the date of the enactment of this Act), over

(ii) the amount which would be the balance in such reserve if the amount of such reserve were determined by assuming that the corporate rate reductions provided in this Act were in effect for all prior periods.

(B) AVERAGE RATE ASSUMPTION METHOD.—The average rate assumption method is the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. Under such method, if timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying—

(i) the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question, by

(ii) the amount of the timing differences which reverse during such period.

SEC. 204. ADDITIONAL TRANSITIONAL RULES.

(a) OTHER TRANSITIONAL RULES.—

(1) URBAN RENOVATION PROJECTS.—

(A) IN GENERAL.—The amendments made by section 201 shall not apply to any property which is an integral part of any qualified urban renovation project.

(B) QUALIFIED URBAN RENOVATION PROJECT.—For purposes of subparagraph (A), the term "qualified urban renovation project" means any project—

(i) described in subparagraph (C), (D), (E), or (G) which before March 2, 1986, was publicly announced by a political subdivision of a State for a renovation of an urban area within its jurisdiction,

(ii) described in subparagraph (C), (D) or (G) which before March 1, 1986, was identified as a single unitary project in the internal financing plans of the primary developer of the project, and

(iii) described in subparagraph (C) or (D), which is not substantially modified on or after March 1, 1986.

(C) PROJECT WHERE AGREEMENT OR DECISION IN 1985.—A project is described in this subparagraph if—

(i) a political subdivision granted on July 11, 1985, development rights to the primary developer-purchaser of such project, and

(ii) such project was the subject of a development agreement between a political subdi-

EXHIBIT
SCHEDULE (DJL-7)

Louisiana Power & Light Company
Calculation of Excess Deferred Taxes

Line No.	Description	Amount
1	Account 281 Deferred Taxes	$ 298,482
2	Account 282 Deferred Taxes	184,865,367
3	Account 283 Deferred Taxes	21,423,586
4	Total Deferred Taxes	$ 206,587,435
5	Total Timing Differences	$ 449,103,120
6	Deferred Taxes @ 34%	152,695,061
7	Excess Deferred Taxes	53,892,374
8	Depreciation Expense	112,260,607
9	Net Plant	3,405,515,098
10	Remaining Life (Years)	30.3358
11	Annual Excess Deferred Taxes	$ 1,776,527

Sources:

Line 1; FERC Form 1, 1985, pg. 269
Line 2; FERC Form 1, 1985, pg. 271
Line 3; FERC Form 1, 1985, pg. 273
Line 4; sum of lines 1-3
Line 5; line 4/.46
Line 6; line 5 * .34
Line 7; line 4 less line 6
Line 8; Updated COS, pg. 4 of 4, line 12, column 36
Line 9; Updated COS, pg. 4 of 4
Line 10; (1/line 8)*line 9
Line 11; line 7/line 10

EXHIBIT ____

Schedule (DJL-8)

Louisiana Power & Light Company — For Cost of Service Program — REVISED 04-Nov-86 — 1 of 4

L P S C Return on Rate Base
At December 31, 1985

(1) Line No.	(2) Account	(3) Actual L P S C	(4) Investment in SFI	(5) Customer Deposits	(6) Coop Transm Charges	(7) Income Taxes	(8) Texaco Settlement	(9) Payroll Increases	(10) Employee Benefits	(11) Property Taxes
1	Operating Revenues									
2	Retail Revenues	1,173,716,446								
3	Unbilled Revenues	16,963,560								
4	Resale revenues	0			0					
5	Total Sales Revenue	1,190,680,006	0	0	0	0	0	0	0	0
6	Other Oper. Revenues	12,560,435	5,355,643						679	
7	Off System Revenues	28,053,273								
8	Total Operating Revenues	$1,231,293,714	$5,355,643	$0	$0	$0	$0	$0	$679	$0
9										
10	Operating Expenses:									
11	Operation and Maintenance	$940,139,954		$1,588,595	$0			2,333,472	$1,456,053	
12	Depreciation	65,657,098								
13	Taxes Other Than Inc. Tax	35,952,012							199,385	2,676,353
14	Federal Income Taxes	(16,608,860)	2,266,463		0	(10,482,162)		(987,525)	(701,402)	(1,132,633)
15	State Income Taxes	(2,770,508)	428,549		0	(4,951,511)		(186,678)	(132,522)	(214,108)
16	Def Fed.Inc.Tax-Net	17,236,637				11,028,895				
17	Def St.Inc.Tax-Net	10,988,246				1,660,351				
18	Investment Tax Credit-Net	(435,181)				(629,178)				
19										
20	Total Operating Expenses	1,050,159,398	2,695,012	1,588,595	0	(3,373,605)	0	1,159,269	821,514	1,329,612
21										
22	Net Operating Income	181,134,316	2,660,631	(1,588,595)	0	3,373,605	0	(1,159,269)	(820,835)	(1,329,612)
23	AFUDC	124,290,666								
24										
25	Return on Rate Base	$305,424,982	$2,660,631	($1,588,595)	$0	$3,373,605	$0	($1,159,269)	($820,835)	($1,329,612)
26										
27	Rate Base (average test year)									
28	Plant in Service	2,813,392,214								
29	Const. Work in Progress	1,310,840,328							97,122	
30	Plant Held for Future Use	4,503,290								
31	Plant Acquis. Adjustment	775,977								
32	Plant Leased to Others	5,017,934								
33	Nuclear Fuel	12,524,227								
34	Accum. Prov. for Deprec.	(559,847,165)								
35										
36	Net Plant	3,587,206,805	0	0	0	0			97,122	0
37	Working Capital	43,656,458	0	0	0			291,684	182,007	0
38	Investment in SFI	0	52,593,902							
39	Deferred Fuel Costs	(14,282,112)								
40	Deferred ITC Pre-1971	(2,858,187)								
41	Acc. Def. Income Taxes	(126,547,417)								
42	Customer Adv. for Const.	(10,776,559)								
43	Customer Deposits	0		(26,441,403)						
44	Def. Texaco Settlement	(472,018,769)					58,401,895			
45	Unamort. Gain Build. Sale	(10,118,327)								
46	Standard Coal Plant	0								
47	Deferred Waterford 3 Expn.	10,060,000								
48										
49	Total Rate Base	$3,004,321,892	$52,593,902	($26,441,403)	$0	$0	$58,401,895	$291,684	$279,129	$0
50										
51	Percent Return on Rate Base	10.17%								

(1) Line No.	(2) Account	(12) Deferred Income Taxes	(13) St. Rosalie Abandonment	(14) Rate Increase	(15) Waterford 3 In Service	(16) Deferred W-3 Expenses	(17) Capacity Charges	(18) Revenue Changes	(18A) Allocation Adjustment	(19) Property Gain
1	Operating Revenues									
2	Retail Revenues			288,550,695				(26,664,874)	(44,566)	
3	Unbilled Revenues								0	
4	Resale revenues								0	
5	Total Sales Revenue	0	0	288,550,695	0	0	0	(26,664,874)	(44,566)	0
6	Other Oper. Revenues								(1,814)	
7	Off System Revenues								35,867	
8	Total Operating Revenues	$0	$0	$288,550,695	$0	$0	$0	($26,664,874)	($10,513)	$0
9										
10	Operating Expenses:									
11	Operation and Maintenance		($3,185,606)		$68,500,282	($185,880,000)	($5,870,128)	($6,814,455)	(285,583)	($251,985)
12	Depreciation				45,116,560				653,681	
13	Taxes Other Than Inc. Tax			1,161,668	1,203,671			(107,349)	(29,210)	
14	Federal Income Taxes		1,348,148	121,623,036	(70,512,610)	0	2,484,238	(8,355,267)	(985,240)	106,640
15	State Income Taxes	0	254,849	22,991,122	(13,329,416)	0	469,610	(1,579,446)	(86,524)	20,159
16	Def Fed.Inc.Tax-Net	371,826			21,920,569	78,664,416			504,718	
17	Def St.Inc.Tax-Net	(3,588,683)			4,143,775	14,870,400			220,578	
18	Investment Tax Credit-Net								(2,270)	
19										
20	Total Operating Expenses	(3,216,857)	(1,582,609)	145,775,826	57,042,831	(92,345,184)	(2,916,280)	(16,856,517)	(9,851)	(125,186)
21										
22	Net Operating Income	3,216,857	1,582,609	142,774,869	(57,042,831)	92,345,184	2,916,280	(9,808,357)	(662)	125,186
23	AFUDC				(124,290,666)				0	
24										
25	Return on Rate Base	$3,216,857	$1,582,609	$142,774,869	($181,333,497)	$92,345,184	$2,916,280	($9,808,357)	($662)	$125,186
26										
27	Rate Base (average test year)									
28	Plant in Service				1,140,833,530				(4,242,195)	
29	Const. Work in Progress				(1,287,046,125)				1,204,896	
30	Plant Held for Future Use								(2,610)	
31	Plant Acquis. Adjustment								2,619	
32	Plant Leased to Others								(2,807)	
33	Nuclear Fuel				9,283,809				(28,235)	
34	Accum. Prov. for Deprec.				(18,022,683)				(91,045)	
35										
36	Net Plant	0	0	0	(154,951,469)	0	0	0	(3,159,377)	0
37	Working Capital	0	0	0	8,562,535	0	0	0	24,858	(31,498)
38	Investment in SFI								(14,408)	
39	Deferred Fuel Costs								3,912	
40	Deferred ITC Pre-1971								(9,646)	
41	Acc. Def. Income Taxes	529,622			(9,103,792)	(46,767,408)			(629,634)	
42	Customer Adv. for Const.								4,140	
43	Customer Deposits								0	
44	Def. Texaco Settlement								93,416	
45	Unamort. Gain Build. Sale								220,386	
46	Standard Coal Plant								426,767	
47	Deferred Waterford 3 Expn.					92,940,000			0	
48										
49	Total Rate Base	$529,622	$0	$0	($155,492,726)	$46,172,592	$0	$0	($3,039,586)	($31,498)
50										
51	Percent Return on Rate Base									

(1) Line No.	(2) Account	(20) Special Study	(21) Standard Coal Plant	(22) Storm Damages and I & D	(23) '87 Payroll Increase	(24) '87 Employee Benefits	(25) '87 Deferred Income Tax	(26) '87 ST. Rosalie Abandonment	(27) '87 Texaco Settelment	(28) '87 Nuclear Oper Licen
1	Operating Revenues									
2	Retail Revenues									
3	Unbilled Revenues									
4	Resale revenues									
5	Total Sales Revenue	0	0	0	0	0	0	0	0	0
6	Other Oper. Revenues									
7	Off System Revenues									
8	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
9										
10	Operating Expenses:									
11	Operation and Maintenance	$2,836,000	($38,542,598)	$3,377,105	$1,421,901	$33,561		$3,185,606		$1,125,197
12	Depreciation									
13	Taxes Other Than Inc. Tax					91,036				
14	Federal Income Taxes	(1,200,195)	9,794,110	(1,429,191)	(601,749)	(52,729)		(1,348,148)	0	(476,183)
15	State Income Taxes	(226,880)	1,851,439	(270,168)	(113,752)	(9,968)		(254,849)	0	(90,016)
16	Def Fed.Inc.Tax-Net		6,517,117				1,823,861			
17	Def St.Inc.Tax-Net		1,123,969				(764,617)			
18	Investment Tax Credit-Net									
19										
20	Total Operating Expenses	1,408,925	(19,255,963)	1,677,746	706,400	61,900	1,059,244	1,582,609	0	558,998
21										
22	Net Operating Income	(1,408,925)	19,255,963	(1,677,746)	(706,400)	(61,900)	(1,059,244)	(1,582,609)	0	(558,998)
23	AFUDC									
24										
25	Return on Rate Base	($1,408,925)	$19,255,963	($1,677,746)	($706,400)	($61,900)	($1,059,244)	($1,582,609)	$0	($558,998)
26										
27	Rate Base (average test year)									
28	Plant in Service									
29	Const. Work in Progress									
30	Plant Held for Future Use									
31	Plant Acquis. Adjustment									
32	Plant Leased to Others									
33	Nuclear Fuel									
34	Accum. Prov. for Deprec.									
35										
36	Net Plant	0	0	0	0	0	0	0	0	0
37	Working Capital	354,500	(4,817,825)	422,138	177,738	4,231		0	0	123,377
38	Investment in SFI									
39	Deferred Fuel Costs									
40	Deferred ITC Pre-1971									
41	Acc. Def. Income Taxes		(8,179,591)				(529,622)			
42	Customer Adv. for Const.									
43	Customer Deposits									
44	Def. Texaco Settlement								55,191,245	
45	Unamort. Gain Build. Sale									
46	Standard Coal Plant		40,683,853							
47	Deferred Waterford 3 Expn.									
48										
49	Total Rate Base	$354,500	$27,686,437	$422,138	$177,738	$4,231	($529,622)	$0	$55,191,245	$123,377
50										
51	Percent Return on Rate Base									

Louisiana Power & Light Company
L P S C Return on Rate Base
At December 31, 1985

REVISED
04-Nov-86

(1) Line No.	(2) Account	(29) '87 W-3 Increase	(30) Sub Total	(31) '87 New Tax Law	(32) Tax Effect on Int. Syncro.	(33) Commis. Plan Phase in Adj.	(34) Adjusted Data	(35) Inc W/O P-I 12.75	(36) Total	(37) Total Increase Incl Phase-In
1	Operating Revenues									
2	Retail Revenues		1,435,557,701			81,577,374	1,517,135,075	72,139,460	1,589,274,535	153,716,834
3	Unbilled Revenues		16,963,560				16,963,560		16,963,560	0
4	Resale revenues		0				0		0	0
5	Total Sales Revenue	0	1,452,521,261	0	0	81,577,374	1,534,098,635	72,139,460	1,606,238,095	153,716,834
6	Other Oper. Revenues		17,914,943				17,914,943		17,914,943	0
7	Off System Revenues		28,089,140				28,089,140		28,089,140	0
8	Total Operating Revenues	$0	$1,498,525,344	$0	$0	$81,577,374	$1,580,102,718	$72,139,460	$1,652,242,178	$153,716,834
9										
10	Operating Expenses:									
11	Operation and Maintenance	$29,515,915	814,683,286			$68,666,667	883,349,953		883,349,953	
12	Depreciation	833,268	112,260,607				112,260,607		112,260,607	
13	Taxes Other Than Inc. Tax	351,764	41,499,330			328,420	41,827,750	290,424	42,118,174	
14	Federal Income Taxes	(13,397,496)	9,351,244	(12,698,678)	5,744,760	29,103,297	31,500,623	27,320,586	58,821,209	
15	State Income Taxes	(2,532,608)	(733,226)	0	1,208,628	6,122,984	6,598,386	5,747,923	12,346,309	
16	Def Fed.Inc.Tax-Net	404,856	138,472,895	2,708,967		(26,110,491)	115,071,371		115,071,371	
17	Def St.Inc.Tax-Net	76,532	28,730,551			(5,493,333)	23,237,218		23,237,218	
18	Investment Tax Credit-Net		(1,066,629)				(1,066,629)		(1,066,629)	
19										
20	Total Operating Expenses	15,252,231	1,143,198,058	(9,989,711)	6,953,388	72,617,544	1,212,779,279	33,358,933	1,246,138,212	
21										
22	Net Operating Income	(15,252,231)	355,327,286	9,989,711	(6,953,388)	8,959,830	367,323,439	38,742,976	406,103,966	
23	AFUDC		0			0	0		0	
24										
25	Return on Rate Base	($15,252,231)	355,327,286	$9,989,711	($6,953,388)	$8,959,830	$367,323,439	$38,742,976	$406,103,966	
26										
27	Rate Base (average test year)									
28	Plant in Service	33,906,906	3,983,890,455				3,983,890,455		3,983,890,455	
29	Const. Work in Progress		25,096,221				25,096,221		25,096,221	
30	Plant Held for Future Use		4,500,680				4,500,680		4,500,680	
31	Plant Acquis. Adjustment		778,596				778,596		778,596	
32	Plant Leased to Others		5,015,127				5,015,127		5,015,127	
33	Nuclear Fuel		21,779,801				21,779,801		21,779,801	
34	Accum. Prov. for Deprec.	(414,464)	(578,375,357)				(578,375,357)		(578,375,357)	
35										
36	Net Plant	33,492,442	3,462,685,523	0	0	0	3,462,685,523	0	3,462,685,523	
37	Working Capital	3,689,489	52,639,692	0	0	0	52,639,692		52,639,692	
38	Investment in SFI		52,579,494				52,579,494		52,579,494	
39	Deferred Fuel Costs		(14,278,200)				(14,278,200)		(14,278,200)	
40	Deferred ITC Pre-1971		(2,867,833)				(2,867,833)		(2,867,833)	
41	Acc. Def. Income Taxes	(241,614)	(191,469,456)	(1,354,483)		(83,433,424)	(276,257,363)		(276,257,363)	
42	Customer Adv. for Const.		(10,772,419)				(10,772,419)		(10,772,419)	
43	Customer Deposits		(26,441,403)				(26,441,403)		(26,441,403)	
44	Def. Texaco Settlement		(358,332,213)				(358,332,213)		(358,332,213)	
45	Unamort. Gain Build. Sale		(9,897,941)				(9,897,941)		(9,897,941)	
46	Standard Coal Plant		41,110,620				41,110,620		41,110,620	
47	Deferred Waterford 3 Expn.		103,000,000			171,666,667	274,666,667		274,666,667	
48										
49	Total Rate Base	$36,940,317	$3,097,955,864	($1,354,483)	$0	$88,233,243	$3,184,834,624	$0	$3,184,834,624	
50										
51	Percent Return on Rate Base						11.53%		12.75%	

Louisiana Power & Light Company
All Jurisdictions
Explanation of Adjustments in the
Pro Forma Return on Rate Base and Rate Base
At December 31, 1985

Column	Explanation
4	INVESTMENT IN SFI. Interest income received in the 12 months ended December 31, 1985 and related taxes on other income are reclassified for ratemaking purposes as operating revenues and operating income taxes, respectively. Adjustment is also made to include the investment in SFI in the rate base.
5	CUSTOMER DEPOSITS. Interest on customer deposits is reclassified as an operating expense and customer deposits is included as a reduction of rate base.
6	COOPERATIVE TRANSMISSION CHARGES. The transmission charges to cooperatives are reclassified for ratemaking purposes from a credit to purchased power expenses to operating revenues.
7	INCOME TAXES. This adjustment eliminates two out-of-period adjustments to income taxes, deferred income taxes and investment tax credit-net recorded in 1985 applicable to years prior to 1985.
8	TEXACO SETTLEMENT. The rate base is increased as a result of the anticipated decrease in 1986 of the average amount of Texaco Settlement funds deferred.
9	PAYROLL INCREASES. This adjustment gives effect to the annualization of an average increase of 4.46% in wages and salaries, exclusive of Waterford 3, given in April 1985 which are to be charged to operation and maintenance expenses.
10	EMPLOYEE BENEFITS. This adjustment reflects the changes affecting the Company's savings plan, group life insurance and pension plan programs and FICA allocated to operation and maintenance and taxes other than income taxes and related income taxes. In addition, this adjustment adjusts an inadvertant error in 1985 concerning the allocation of employee benefits related to payroll. The rate base reflects the increase in CWIP and working capital.

Louisiana Power & Light Company
All Jurisdictions
Explanation of Adjustments in the
Pro Forma Return on Rate Base and Rate Base
At December 31, 1985

Column	Explanation
11	PROPERTY TAXES. The 10-year exemptions on Waterford Unit Nos. 1 and 2 ends 12/31/85. This adjustment gives effect to the estimated net increase in property taxes in 1986 attributable to such units and other taxable property additions.
12	DEFERRED INCOME TAXES. This column reflects the last of 3 years' amortization of the net excess deferred income taxes attributable to liberalized depreciation from each of the vintage year's composite federal and state income tax rates to the current composite federal and state income tax rates. Also included is a reversal of a 1984 vintage year adjustment made in 1985.
13	ST. ROSALIE ABANDONMENT. In accordance with LPSC Order No. U-15684, this adjustment returns to ratepayers over a 3-year period the costs of the St. Rosalie abandonment prorated to the other companies of the Middle South System.
14	RATE INCREASE. This column gives the effect of annualizing the additional revenue increase of $285,429,000 granted by the LPSC in its Order No. U-16945.
15	WATERFORD 3 IN SERVICE. Operation (exclusive of fuel costs) and maintenance, depreciation (including decommissioning), taxes other than income taxes and income taxes are included in operating expenses to annualize the unit's initial year of service. In addition, income taxes and deferred federal income taxes are adjusted to reflect the additional tax depreciation taken. As for the rate base, the balance cost of the unit is transferred from CWIP to Plant in Service, accumulated depreciation reflects the annualization of the initial year's depreciation expense and accumulated deferred income taxes are adjusted as above.
16	DEFERRED WATERFORD 3 EXPENSES. The adjustment annualizes the deferred Waterford 3 expenses in accordance with the LPSC Order No. U-16945.
17	CAPACITY CHARGES. This adjustment reflects the annualization of the changes in the demand costs of White Bluff, reserve equalization and Grand Gulf 1.

Louisiana Power & Light Company
All Jurisdictions
Explanation of Adjustments in the
Pro Forma Return on Rate Base and Rate Base
At December 31, 1985

Column	Explanation
18	REVENUE CHANGES. Revenue is reduced as a result of changes in rate schedules of certain industrial customers.
19	PROPERTY GAIN. The Company recorded in Other Income a gain of sale of certain property during the year 1985. This adjustment reclassifies the gain as a reduction in O&M.
20	SPECIAL STUDY. This adjustment reflects, for ratemaking purposes, the amortization of a special study over a three-year period.
21	STANDARD COAL PLANT. In December 1985, the Company recorded a writedown of the Company's share of certain costs applicable to the Middle South System's indefinitely delayed future fossil generating facilities totalling approximately $44.4 million. For ratemaking purposes, the Company is requesting recovery of this writedown over a 10-year period, and the unamortized balance be included in the rate base.
22	STORM DAMAGES AND INJURIES & DAMAGES. This adjustment requests increases to recover the large amounts charged to the reserves in recent years, $1.2 million for storm damage and $2.3 million for public liability and property damage.
23	1987 ADJUSTMENT - PAYROLL INCREASES. This adjustment annualizes proformed 1986 payroll increases excluding Waterford 3 (Column 9) to reflect increases in 1987 through the rate effective 11/20/87 at the same weighted average increase as 1986. Such 1986 payroll increases were effective to April 1987.
24	1987 ADJUSTMENT - EMPLOYEE BENEFITS. As in the case of the 1987 Adjustment - Payroll Increases, this adjustment reflects the effect of employee benefit increases in the same manner.
25	1987 ADJUSTMENT - DEFERRED INCOME TAXES. This adjustment removes the "48-46" deferred income taxes shown in Column 12 as it is the last year of the 3-year amortization, 1984 - 1986.
26	1987 ADJUSTMENT - ST. ROSALIE ABANDONMENT. This adjustment reverses Column 13 as the 3-year amortization began in 1984, for ratemaking purposes, and ends in 1986.

Louisiana Power & Light Company
All Jurisdictions
Explanation of Adjustments in the
Pro Forma Return on Rate Base and Rate Base
At December 31, 1985

olumn	Explanation
27	1987 ADJUSTMENT - TEXACO SETTLEMENT. In February 1987, the Company will refund $56.4 million of the funds received from Texaco. This adjustment increases the rate base by the amount of this refund.
28	1987 ADJUSTMENT - NUCLEAR POWER REACTOR FEE. The NRC has proposed a user fee of $1.01 million per reactor for all utilities having nuclear generating units. This adjustment covers such annual costs applicable to Waterford 3 and the Company's 14% share of Grand Gulf 1.
29	1987 WATERFORD 3 INCREASES. This adjustment covers the estimated increase in Waterford 3's operating expenses (exclusive of the amount shown in Column 28) for the 12 months ended 9/30/87.
31	1987 NEW TAX LAW. This adjustment assumes that Congress will vote for a proposed change in the federal statutory corporate income tax rate from 46% to 34% effective 7/1/87. No other provisions to the proposed change have been assumed. In addition, this adjustment reverses the 1985 tax loss carryforward from a deferred federal income tax item to a federal income tax item.
32	TAX EFFECT ON INTEREST SYNCHRONIZATION. Income taxes are increased by the tax effect of the proforma interest charges as compared to the interest charges per books for the year 1985.
33	PHASE-IN ADJUSTMENT. This adjustment reflects the phase-in to rates one-third of the Deferred Waterford 3 Expenses, or $68.7 million, plus incremental carrying charges.
35	INCREASE TO EARN 12.75% AFTER PHASE-IN. This adjustment covers the remainder of the increase requested in order for the Company to earn 12.75% on its rate base.

EXHIBIT ____

Schedule (DJL-9)

EXHIBIT
SCHEDULE (DJL-9)

Louisiana Power & Light Company
Calculation of Deferred Taxes Related to Deferred Costs

Line No.	Description	Amount
1	Expense Deferral	$206,000
2	Deferred Taxes	94,760
3	Overall Return	.1275
4	Return Impact	12,082
5	Pre-tax Cost of Capital	.197
6	Revenue Requirement Reduction Grossed Up for Taxes	$ 18,668
7	LPSC Expense Deferral	$206,000
8	Deferred Tax Impact	(18,668)
9	Adjusted Deferral	$187,332

Sources:

Line 1; Table 1, line 11
Line 2; Line 1 * .46
Line 3; Order U-16945
Line 4; Line 3 * line 2
Line 5; Table A, line 3
Line 6; Line 5 * line 2

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June 19, 1986

OUR FILE NUMBER
28,364

H. A. Vondenstein, Esq.
Parish Attorney
Jefferson Parish
New Courthouse
Post Office Box 9
Gretna, Louisiana 70074

Re: Louisiana Power & Light Co., Ex Parte.
In re: Application for Approval of Increased Rates for Retail Electric Service, Docket No. U-16945 Before the Louisiana Public Service Commission

Dear Mr. Vondenstein:

I transmit the response of the Louisiana Public Service Commission Staff to the Requests for Information that were handed out by Jefferson Parish after the Public Service Commission issued its Order No. U-16945.

Sincerely,

Michael R. Fontham
Of STONE, PIGMAN, WALTHER,
WITTMANN & HUTCHINSON

MRF:ku
Enc.

cc: All Counsel of Record
Louis S. Quinn, Esq.

RESPONSES OF THE LOUISIANA
PUBLIC SERVICE COMMISSION STAFF
TO REQUESTS FOR INFORMATION

RE COMMISSION ORDER NO. U-16945

GENERAL STATEMENT

Order No. U-16945 was issued by the Commission as part of an expedited emergency consideration of the rate request of Louisiana Power & Light Co. A full evidentiary case, with exhibits, was not placed into the record by the Staff because of time constraints. In response to the request for information, the Commission's consultants developed Table A, attached.

Request #1 Please provide a detailed description, calculations, assumptions and considerations employed in calculating the impact on base rates of LP&L absorbing $284 million of Waterford 3 related costs. The information should be provided in sufficient detail as to permit replication of the results.

Response #1 See Table A attached.

Request #2 Please provide a detailed description, calculations, assumptions, and considerations employed in calculating the impact on base rates of the carrying charges associated with the LP&L deferral of $206 million in revenue requirement. The information should be provided in sufficient detail as to permit replication of the results.

Response #2 See Table A attached.

Request #3 Please provide a detailed description, calculations, assumptions and considerations employed in calculating the impact on base rates of the reduced depreciation expense associated with the provision that LP&L permanently absorb $284 million of Waterford 3 costs. The information should be provided in sufficient detail as to permit replication of the results.

Response #3 See Table A attached.

Request #4 — Please provide a detailed description, calculations, assumptions and considerations employed in calculating the impact on base rates of MSE permanently absorbing 18% of the 14% share of Grand Gulf allocated to LP&L. The information should be provided in sufficient detail as to permit replication of the results.

Response #4 — See Table A attached.

Request #5 — Please provide a detailed breakdown and explanation, assumptions, calculations, considerations and workpapers utilized that set forth the reductions to the $444 million revenue requirement requested by LP&L down to the $190.7 million revenue requirement order by the LPSC in Order No. U-16945.

Response #5 — See Table A attached.

Request #6 — Please provide a detailed cost of service and rate base which reflects the results of Order No. U-16945. In other words, please provide the detail of rate base and expenses which will be the starting point of any future rate matters with respect to LP&L's request for permanent rate relief.

Response #6 — Inasmuch as the Company premised its request on a 6/30/85 test year, Staff, consistent with past practice, would request an updated test year reflecting the most up-to-date information relating to investment, operating and capital costs. Accordingly, the information requested is not yet available and therefore cannot be provided at this time. Staff expects to request information from LP&L in the near future for a test year ending December 31, 1985.

Request #7 — Please provide a copy of the MSE (Grand Gulf) settlement.

Response #7 — Staff assumes that this request refers to settlement papers that were never executed. A copy of a proposed settlement agreement is being provided to Jefferson Parish with this response and will be made available to other parties upon request. The relevant terms are explained in Order No. U-16945.

TABLE A

LP&L REVENUE REQUIREMENT

INTERIM RATE ORDER

($000,000)

LINE NO. (A)	ITEM (B)		AMOUNT (C)
1.	LPSC Revenue Requirement as Filed - Waterford 3		$ 444
2.	Depreciation on Additional Cost at Completion ($2.840 - $2.773 x .967[1] x .025[3])		3
3.	Return on Additional Cost at Completion ($2.840 - $2.733 x .982[2] x .967 x .197[4])		20
4.	Total LPSC Revenue Requirement at Full Cost to Complete		467
5.	Total Cost to Complete Plant in Service	2,840	
6.	Cost Absorbed by LP&L @ 10%	284	
7.	LPSC Depreciation Absorption (284 x .967 x .025)		(7
8.	LPSC Return Absorption (284 x .982 x .967 x .197)		(53
9.	Allowable LPSC Waterford 3 Revenue Requirement		407
10.	Current Revenue - Before Carrying Costs		201
11.	Deferred Costs		206
12.	Carrying Charge on the Deferral (206 x .13 x .5)[5]		14
13.	Total LPSC Current Revenue - Waterford 3 (L10 + L12)		215
14.	Total LPSC Grand Gulf Annual Revenue Requirement (970 x .14 x .995)[6]	135	
15.	Grand Gulf Absorption (135 x .18)		(24
16.	Net Base Rate Increase (L13 - L15)		191
17.	Additional Cost of Energy Buy-Back (1,125,000 kw x .575 x 876 x .14 x .78)($.046 - $.015)		4

1/ .967 is the LPSC retail allocation factor.

2/ .982 is the ratio of rate base to Plant in Service, after taking account of the reserves for depreciation and deferred taxes.

3/ Estimated Waterford 3 depreciation rate.

4/ Pre-tax cost of capital consistent with filed rate of return of 12.75%.

EXHIBIT ____

Schedule (DJL-10)

EXHIBIT
SCHEDULE (DJL-10)

Louisiana Power & Light Company
Calculation of Imprudence Disallowance
Based on Two-Year Delay in Waterford 3

Line No.	Description (a)	Estimated Project Costs (b)	Estimated Imprudence Disallowance (c)
1	Waterford 3 Project Cost	$3,300,000,000	
2	One-Year Project Discounted Cost	3,005,738,228	
3	Cost of First Year Delay		$294,261,772
4	Second Year Project Discounted Cost	$2,737,715,847	
5	Cost of Second Year Delay		268,022,381
6	Two-Year Project Cost Delay		$562,284,153
7	Two-Year Fuel Cost Penalty		179,126,000
8	Total Cost of Two-Year Delay		$741,410,153

Source and Reference

Column (b) line 1: TB&A report, page VIII-8
Column (b) line 2: Column (b) line 1 discounted by 9.79%
Column (b) line 4: Column (b) line 2 discounted by 9.79%
Column (c) line 3: Column (b) line 1 less Column (b) line 2
Column (c) line 5: Column (b) line 2 less Column (b) line 4
Column (c) line 6: Column (c) line 3 plus Column (c) line 5
Column (c) line 7: Annual Fuel Savings (Cain Exhibit 1) multiplied by 2
Column (c) line 8: Column (c) line 6 plus Column (c) line 7

AFFIDAVIT

THE STATE OF FLORIDA)
COUNTY OF ORANGE)

Before me, the undersigned authority, on this day personally appeared Daniel J. Lawton, who, having been placed under oath by me, did depose as follows:

"My name is Daniel J. Lawton. I am of legal age and a resident of the State of Florida. The foregoing testimony and exhibits, offered by me on behalf of Jefferson Parish, Louisiana, were prepared by me or under my direction and supervision, and are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct."

Daniel J. Lawton

SUBSCRIBED and SWORN TO BEFORE ME by the said Daniel J. Lawton, this Ninth day of December, 1986.

SHIRLEY BERRY
Notary Public, State of Texas
My Commission Expires May 12, 1990

Shirley Berry
Notary Public in and for
Travis County, Texas

Typed Name: Shirley Berry
My Commission expires: May 12, 1990