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

September 21, 1979

Michael C. Farrar, Esq., Chairman
Atomic Safety and Licensing Appeal Board
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dr. W. Reed Johnson
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U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

DOCKETED USNRC SEP 24 1979 Office of the Secretary Docketing & Service Section

In the Matter of
FLORIDA POWER & LIGHT COMPANY
(St. Lucie Nuclear Power Plant, Unit 2)
Docket No. 50-389

Gentlemen:

Enclosed please find the testimony of Robert G. Fitzpatrick and Byron L. Siegel of the NRC Staff prepared in response to questions posed by this Board in ALAB-537. Also enclosed is testimony provided to the NRC Staff by Edward J. Fowlkes of the Federal Energy Regulatory Commission which was prepared to respond to Question B1 as stated in ALAB-537. For the information of the Board and the parties, a letter to Dr. Robert E. Uhrig from Robert L. Baer dated September 17, 1979 is included. That letter identifies the confirmatory testing requirement addressed in Mr. Siegel's testimony.

Sincerely,

William J. Olmstead

William J. Olmstead
Counsel for NRC Staff

Enclosures: As Stated

cc (w/encls.):

Michael Glaser, Esq.
Dr. David L. Hetrick
Martin Harold Hodder, Esq.
Dr. Frank Hooper
Dr. Marvin M. Mann
Harold F. Reis, Esq.
Norman A. Coll, Esq.

Atomic Safety and Licensing Board Panel
Atomic Safety and Licensing Appeal Board
Docketing and Service Section

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SEP 17 1979

Docket No. 50-389

Dr. Robert E. Uhrig
Vice President of Nuclear and
General Engineering
Florida Power and Light Company
P. O. Box 529100
Miami, Florida 33152

Dear Dr. Uhrig:

SUBJECT: ADEQUACY OF REACTOR COOLANT PUMP SEAL DESIGN DURING POSTULATED STATION BLACKOUT CONDITIONS (St. Lucie Plant, Unit No. 2)

One of the open issues related to ALAB-537 pertaining to St. Lucie Nuclear Power Plant, Unit 2, involves the stability of the Florida Power and Light Company's electrical grid (Question B2 of ALAB-537). In response to the ALAB order of March 10, 1978, both the staff and the Florida Power and Light Company discussed the consequences of offsite power with simultaneous on-site power failure (station blackout). Florida Power and Light Company suggested that the first significant milestone encountered would be excessive core heating due to loss of water from the condensate storage tank about 16 hours after loss of all AC power (Flugger Affidavit of March 31, 1978). The staff judgment was that a loss of reactor coolant pump seals at about one hour after loss of all AC power - resulting in a loss of coolant accident (Fitzpatrick Affidavit of June 12, 1978) would be more limiting.

We have evaluated the potential of reactor coolant pump seal failures for the duration of time the plant would be subjected to a total loss of AC power (see Enclosure). Based on our evaluation we require that a confirmatory test on one of the four seal assemblies that comprises the seal cartridge be performed under expected blackout conditions of temperature, pressure and time, to provide the additional verification necessary to determine the adequacy of the reactor coolant pump seal design. The results of this test should be included in the FSAR for St. Lucie Plant, Unit No. 2, when it is filed.

Sincerely,
Original Signed by

Robert L. Baer, Chief
Light Water Reactors Branch No. 2
Division of Project Management

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In the Matter of FLORIDA POWER & LIGHT COMPANY (St. Lucie Nuclear Power Plant Unit No. 2)	)))))	Docket No. 50-389

Affidavit of Byron L. Siegel

I, Byron L. Siegel; being duly sworn to depose and state:

1. I am a Nuclear Reactor Engineer in the Office of Nuclear Reactor Regulation.

2. I have prepared a statement of professional qualifications which is attached to this affidavit.

3. I have prepared testimony in the captioned proceeding addressing the Appeal Board's Question numbered B2 as stated in ALAB-537.

This question requested the staff and applicant to analyze events that would occur between the loss of all AC power and the violation of either the fuel design limits or the design conditions of the reactor coolant pressure boundary and in particular the differing responses of the NRC staff and applicant to Question B.1(b) of the Appeal Boards March 10, 1978 Order pertaining to the most limiting safety related failure.

I hereby certify that the above statements are true and correct to the best of my knowledge and belief.

Byron L. Siegel
Byron L. Siegel

Subscribed and sworn to
before me this 7th day of September , 1979

Notary Public

My Commission expires: July 1, 1982.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In the Matter of FLORIDA POWER & LIGHT COMPANY (St. Lucie Nuclear Power Plant Unit No. 2)	))))	Docket No. 50-389

NRC STAFF TESTIMONY
OF
BYRON L. SIEGEL

INTRODUCTION

This testimony addresses Appeal Board Question B2 relevant to the analysis of events that would occur between the total loss of all AC power and the violation of either the fuel design limits or the design conditions of the reactor coolant pressure boundary and in particular the differing responses of the NRC staff and the applicant to Question B.1(b) of the Appeal Boards March 10, 1978 Order pertaining to the most limiting safety related failure.[1/]

1/ Question B2

In line with the above discussion, the testimony is to analyze events that would occur between the "loss of all AC power" and the violation of either the fuel design limits or the design conditions of the reactor coolant pressure boundary (or any portion thereof). In particular, the parties should, if possible, reconcile their differing responses to question B.1(b) of our March 10, 1978 order, 29/ or, if not, point up precisely where the disagreements lie.

29/ [References fn 24 reproduced below:]

Applicant suggests that the first safety related failure encountered would be excessive core heating due to the loss of water from the condensate storage tank, and that this would occur about 16 hours after the loss of AC power (Flugger Affidavit of March 31, 1978, p. 3).

The staff's judgment is that the first failure would be that of a primary pump seal at about one hour after the loss of AC power --- resulting in a small loss of coolant accident. (Fitzpatrick Affidavit of June 12, 1978, p. 11).

I have reviewed the testimony of Frederick George Flugger provided in response to Question B2 of ALAB-537 contained in the Applicant's June 22, 1979 submittal. The Applicant's testimony addresses failure of a reactor coolant pump seal thus apparently reconciling the difference between its March 31, 1978 submittal and the NRC Staff's June 12, 1978 submittal. The content of this testimony, related to the failure of the reactor coolant pump seals, is consistent with the information provided by F. Fehlau (Technical Administrator for Byron Jackson Pumps, manufacturer of the reactor coolant pumps for the St. Lucie Nuclear Power Plant, Unit 2) at a meeting held on May 16, 1979 between the USNRC, staff and the applicant, Florida Power and Light Company. The testimony of Frederick George Flugger concluded that in the event of a station blackout, which results in a loss of cooling water flow to the cartridge seal assembly of the reactor coolant pump, an appreciable leakage path through the seal assembly to the reactor containment building that could result in a significant loss of primary reactor coolant does not exist. The bases for this conclusion were:

1. All seal components are captured within the seal cartridge assembly and held together by hydraulic and spring forces thereby minimizing the leakage paths.
2. Each of the four seals that comprise the seal assembly is designed to provide sealing against full system pressure.
3. All the components that comprise the seal cartridge assembly, except for the elastomeric U-cups and O-rings, are made of materials that are unaffected by the elevated temperatures resulting from a loss of coolant to the seals.
4. Confined O-rings made of the elastomeric material used on the U-cups and O-rings have been used on flanged joints of a reactor coolant pump hot test loop where they have been subjected to temperatures of 550^{O}F for in excess of 100 hours. The O-rings maintained their sealing capability although hardening and permanent set of the O-rings, as expected, occurred.

Based on my review of the information provided, I agree that the above reasons provide strong basis for acceptance of the conclusion that a significant loss of reactor coolant through the seal cartridge will not occur. However, since no test data on the seal design under expected reactor temperatures and pressures following a station blackout and specifically on the elastomeric seals in the geometry utilized in the seal assembly design is available, we have required that the Applicant perform a confirmatory test on at least one of the four seal assemblies that compromise the seal cartrige under expected blackout conditions of temperature, pressure, and time to provide the additional verification necessary to determine the adequacy of the reactor coolant pump seal design.

It is my position that the information provided by the applicant in combination with results from the confirmatory test, which show that the loss of coolant through the reactor coolant pump seals during the duration of station blackout is not sufficient to adversely affect natural circulation, provide adequate assurance that the ability to cool the reactor core will be maintained and that fuel and reactor coolant pressure boundary limits will not be exceeded.

STATEMENT OF PROFESSIONAL QUALIFICATIONS OF BYRON L. SIEGEL

I am a Nuclear Reactor Engineer in the Office of Nuclear Reactor Regulation. I have recently been assigned to the Bulletins and Orders Task Force following the Three Mile Island accident. I am responsible for conducting safety reviews and evaluations for light water reactor emergency core cooling, reactor coolant, and various auxiliary systems assigned to me during the review of nuclear reactor license applications.

I received a Mechanical Engineering Degree in 1955 from City College of New York.

In 1956 I was a petroleum heater design engineer at Foster Wheeler Corporation in New York City, New York.

From 1956 to 1973 I was a Nuclear Engineer in the Nuclear Systems Division at the National Aeronautics and Space Administration (formerly National Advisory Committee for Aeronautics), Lewis Research Center, Cleveland, Ohio. My assignments included:

- 3 years at the Plumbrook Reactor Facility during construction phase.
- Experimental and developmental heat transfer research related to nuclear propulsion and space power applications.
- Project Manager on contracts to fabricate capsules to test fuel element design for space power applications.
- Design of experiments to be tested at the Plumbrook Reactor Facility.
- Responsibility for analysis of test data and evaluation of post-irradiation examinations.

During this time I authored or coauthored approximately 12 reports.

In May 1973 I accepted employment with the Atomic Energy Commission (now the Nuclear Regulatory Commission) in the Reactor Fuels Section, where I reviewed reactor fuel element and assembly designs, thermal performance analyses and operating experience. From May, 1977 to May 1979 I was a member of the Reactor Systems Branch where I was responsible for reviewing safety systems on light water reactors. From [illegible] 1979 I [illegible] assigned to the Bulletins and Orders Task Force where I have been performing reviews of licensee and vendor supplied information to support decisions regarding plant operations.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In the Matter of	)	
	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
	)	
(St. Lucie Nuclear Power Plant, Unit 2)	)	

AFFIDAVIT OF ROBERT G. FITZPATRICK

I, Robert G. Fitzpatrick, being duly sworn to depose and state:

1. I am an electrical engineer and a senior member of the Power Systems Branch of the Nuclear Regulatory Commission.

2. I have prepared a statement of professional qualifications which is attached to this affidavit.

3. I have prepared the testimony attached to this affidavit which addresses questions A1, A2, B1, B2, B3, B4, C and D as stated in ALAB-537.

I hereby certify that the above statements are true and correct to the best of my knowledge and belief.

Robert G. Fitzpatrick

Robert G. Fitzpatrick

Subscribed and sworn to before me
this [illegible] day of September, 1979

My Commission Expires: [illegible]

[illegible]

Notary Public

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In the Matter of	)	
	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
	)	
(St. Lucie Nuclear Power Plant,	)	
Unit 2)	)	

NRC STAFF TESTIMONY

OF

ROBERT G. FITZPATRICK

I. INTRODUCTION

This testimony responds to questions A1, A2, B1, B2, B3, B4, C and D as set forth in ALAB-537 dated April 5, 1979. Part two of my testimony sets forth some background material to provide the Appeal Board a description of the Staff's view of the FP&L grid in general and the onsite and offsite power systems at St. Lucie in particular. Part three addresses the specific ALAB-537 questions and includes Staff comments on the Applicant's responses. Part four is a summary of this testimony.

II. BACKGROUND

Two documents have been previously submitted to the Appeal Board which summarize the FP&L grid system and the St. Lucie power systems: joint testimony prepared by M. Srinivasan and D. McDonald entitled "A Further Evaluation of the Florida Power and Light Company Electric Power System", October 25, 1977 and my testimony of June 12, 1978. The first document provides background material on power systems in general, NRC requirements concerning electrical power systems, a summary of the major FP&L grid system disturbances from 1973 to 1977, and the action the staff has taken in response to these major disturbances. My testimony prepared in response to the Appeal Board's March 10, 1978 order updates the former document with respect to the May 14, 1978 event and subsequent staff actions. It also provides a discussion of NRC requirements concerning electrical power systems and documentation of additional staff positions imposed upon FP&L as a result of the ongoing staff review in the electrical power systems area.

These two documents; when taken together, provide the background material upon which my response to ALAB-537 has been constructed.

III. ALAB-537 QUESTIONS

A. General Design Criterion (GDC) 17[21/]

A1. This criterion, entitled "Electric Power Systems," requires in its third paragraph (emphasis added):

> Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable.

All three transmission lines connecting the St. Lucie station to the applicant's grid originate at the Midway Substation. The May 14, 1978 incident, in which all power at that substation was lost despite redundant incoming sources, demonstrates that these circuits are indeed susceptible to simultaneous failure. The testimony should address whether the St. Lucie station nonetheless meets this GDC-17 requirement.

21/ See 10 CFR Part 50, Appendix A ("General Design Criteria for Nuclear Power Plants").

STAFF ANSWER TO BOARD QUESTION A1

The St. Lucie station is in full conformance with the requirements of GDC-17 including the specific subsection addressed in this question. From the staff's point of view, none of the three St. Lucie to Midway lines failed during the May 14, 1978 incident. The May 14, 1978 incident was a loss of offsite power to the St. Lucie station as was the May 16, 1977 incident. I make a distinction between grid unavailability and circuit failure because it is fundamental to the staff's interpretation of GDC-17. Grid unavailability (i.e., loss of offsite power) is recognized as an anticipated operational occurrence. That is, it is an event that is expected to occur one or more times during the life of the nuclear power station. In this light, the regulations do not require a design which precludes the event but rather the capability of the integrated nuclear power station design to cope with the event if and when it should occur. The St. Lucie to Midway lines were not tripped as part of the sequence of events that lead to the isolation of the Midway Substation and were intact and available to supply St. Lucie with offsite power had it been available. By the staff's interpretation of GDC-17, there have been no simultaneous circuit failures on the St. Lucie to Midway transmission lines.

General Design Criterion 17 is specific in the requirements placed upon the physical configuration of the offsite power system in the close proximity of the nuclear generating unit. The Appeal Board is correct that the "common switchyard" referred to is the one electrically connected directly to the unit generator and onsite distribution system. In most cases this switchyard is located on the site, however. this is not an NRC requirement. A minimum of two transmission lines must connect this switchyard to the offsite power system and a minimum of two lines must connect this switchyard to the onsite distribution system. This is the extent of the physical complement of equipment required by GDC-17 for the offsite power system. Figure A1 (INFRA) depicts, in block diagram form, this minimum physical complement of electrical power system equipment required to meet the requirements of GDC-17. The additional physical requirement placed upon this complement of electrical power system equipment is that the circuits be "located so as to minimize to the extent practical the likelihood of their simultaneous failure." Staff review of this latter aspect of the design (i.e. location) is described in Standard Review Plan 8.2 and those specific subsections which address this subject are attached as Enclosure 2.

There is no NRC requirement concerning how many switchyards out in the grid must be directly connected to the station switchyard. The allowance of a common right-of-way for the offsite power circuits implies the acceptability of terminating at a common distant switchyard subject to the ability of that switchyard to meet the same design criteria as required of the unit switchyard.

The ability of the common grid switchyard (in this case Midway) to meet the same criteria as the common plant switchyard (St. Lucie) is necessary to assure the minimization of simultaneous failure of the grid transmission circuits.

yard is utilized because of the independence of the breaker control systems and associated power supplies and the physical separation of the buses upon which the circuits terminate. Applicable criteria and guidance for the review of a common switchyard are included in Enclosure 2 section III.c. The Midway Substation design meets all of these requirements.

The most important consideration for the required minimum of two offsite power circuits is that they not be the weak reliability link in the offsite power supply system. As long as these offsite power circuits have a reliability equal to or greater than the offsite power system to which they connect, where they connect to this system is of secondary concern. The availability of offsite power to the nuclear unit can be no more than the lesser of the availabilities of the offsite power system or the connecting offsite power circuits. In other words, no matter how many circuits connect a nuclear power generating station to the grid, and no matter how well they are designed and protected from postulated failures, a grid blackout renders them all useless. The above availability considerations are exactly why GDC-17 includes the words "to the extent practical" as it is in recognition of this situation. Based upon the above, it has been and continues to be the staff's conclusion that the St. Lucie design meets the physical configuration requirements of GDC-17.

STAFF RESPONSE TO APPLICANT'S ANSWER TO BOARD QUESTION A1

The applicant states that three separate events led to the May 14, 1978 loss of offsite power at St. Lucie.1/ The Staff does not agree. The first event cited was the planned removal of the 240Kv Ranch to Pratt & Whitney transmission line for testing. This action can not be counted as an independent event. The removal of this transmission line was a premeditated approved action that changed the state of the grid system. It is from this planned new state that one must start counting independent events. In this case the two independent events were a switching error and a previously undetected maintenance error.

Applicant provides an analysis which demonstrates the ability of the Midway Substation to withstand two independent bus failures and still maintain the ties between the grid and St. Lucie.2/ This academic exercise shows some of the inherent flexibility incorporated into a breaker-and-a-half switchyard configuration. This point has very little bearing on the capability of the grid with respect to St. Lucie. Without being quantitative, a bus failure is probably the least likely failure in a power system. To postulate two such independent failures on equipment located so closely together without affecting any of the intervening electrical equipment is of low enough probability to be considered incredible for licensing purposes.

1/ [illegible]

2/ Page 7 Applicant response to Board Question A1.

Applicant also provides an analysis of what changes in reliability could be gained by bringing one of the St. Lucie transmission lines directly to the Ranch Substation.[3/] The analysis appears to be carefully constructed to demonstrate no reliability can be gained by a physical change in the grid system. The staff is not convinced that the modified design, as presented, is the design that the applicant would choose if the Appeal Board should require a grid connection for St. Lucie at other than the Midway Substation. A seemingly much more practical approach would have been to investigate what lower voltage distribution systems in the area of St. Lucie could be tapped for a connection to the nuclear units. This concept would leave the three St. Lucie to Midway lines intact with no reduction in present reliability and would provide a relatively low cost alternative way to supply St. Lucie a grid connection at other than the Midway Substation with a definite increase in overall reliability.

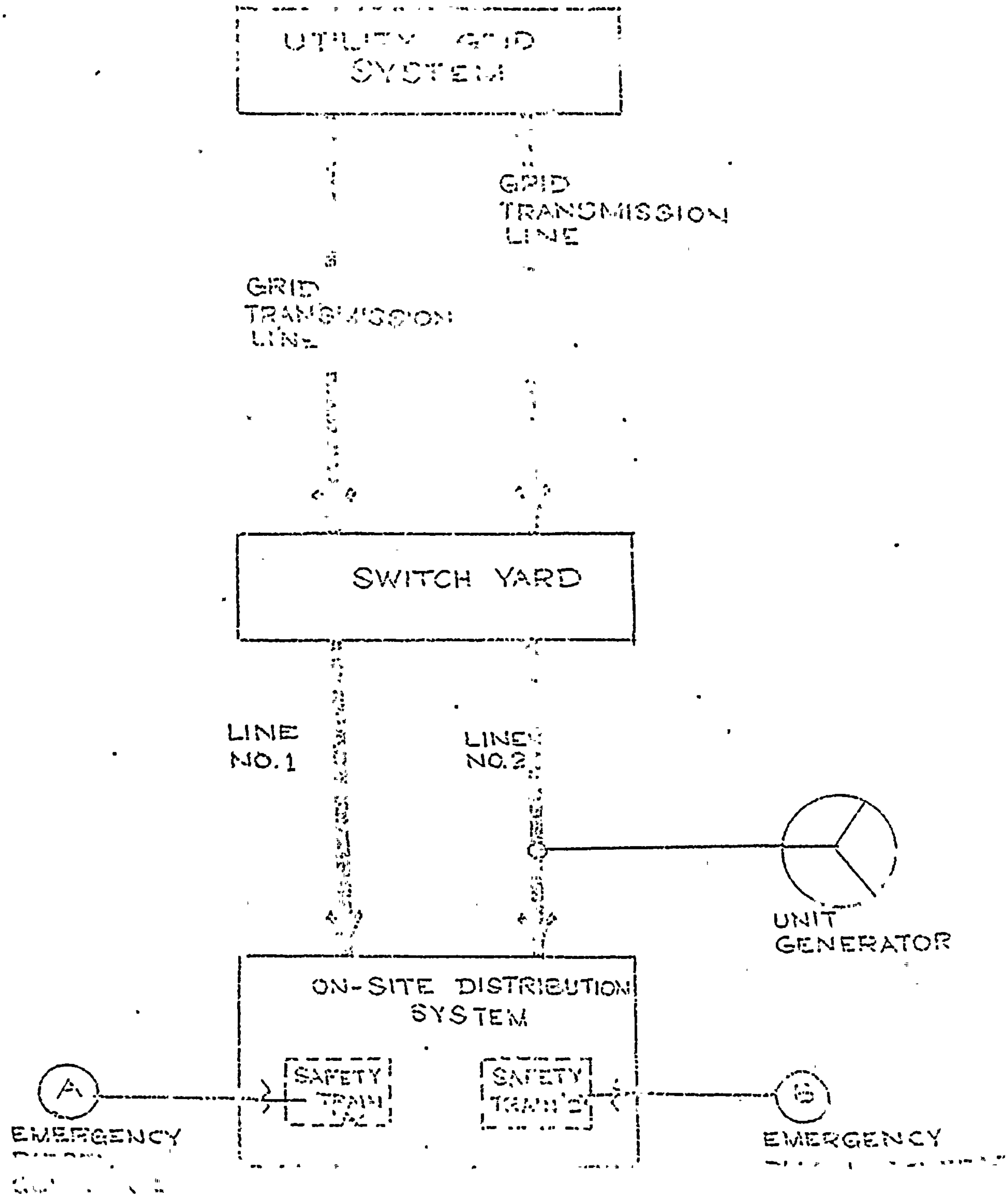
The following is a hypothetical example of a way of providing a separate connection to grid other than at Midway. (The viability and practicality of this or any other hypothetical example would ultimately have to be determined by the applicant.) The source of this example is the grid configuration figure presented in attached #6 to the applicants testimony. on this question. There is a 138Kv right-of-way that crosses the St. Lucie-Midway lines and goes between White City and Jensen. This line could be tapped at its intersection with the St. Lucie to Midway lines. Additional

[3/] Page 8 Applicant response to Board Question A1.

circuit breakers at this end of the line would not be necessary. Because the St. Lucie to Midway lines would not be altered and the existing design already meets GDC-17 requirements, this 138Kv line could be run on one of the three existing lines of transmission towers. This is particularly important as there is only one right of way allowed to the applicant for crossing from the mainland to Hutchison Island. Termination at St. Lucie would require a transformer and some 4Kv switchgear. This line would not be required for bulk power output from the generating units and therefore could be dedicated to the emergency buses with a required power transfer capability equal to the combined emergency loads of the two units. This transfer capability is well within the limits of a 138Kv line. I do not believe it is necessary to make this or any similar modification to the St. Lucie design, however, this is the type of analysis (with further supporting details) that I would have expected from the applicant.

Figure A1

Basic Requirements of GDC 17



A2. For its part, the first paragraph of GDC-17 appears to establish an unattainable set of conditions for electrical power systems generally. It reads as follows (emphasis added):

> An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

This paragraph requires that an assessment of the sufficiency of the offsite power system start with the assumption that the onsite system is not functioning. That assessment must then consider the effect of "anticipated operational occurrences." But loss of the offsite power system itself may reasonably be considered to be such an occurrence. The parties should, therefore, explain how the St. Lucie plant can comply with the literal requirements of this paragraph as written. If it cannot, they should attempt to justify the situation in terms of the purpose of the requirement.

STAFF RESPONSE TO BOARD QUESTION A2

The suggested literal interpretation of GDC-17 must be reconciled with the other regulatory requirements of Part 50. Appendix A of 10 CFR 50 provides a definition of anticipated operational occurrences. One of the examples given is loss of all offsite power. Clearly if all offsite power is lost, offsite power is not available to bring the reactor to a safe shutdown condition. This is true not only of the St. Lucie design but of all nuclear power generating stations. The fact that this particular anticipated operational occurrence can happen is one of the fundamental bases for the requirement of GDC-17 that a single-failure-proof onsite power system, independent of the offsite system, be included in the design. I believe the Staff's interpretation and enforcement of this aspect of GDC-17 is consistent with the purpose of the criterion.

STAFF RESPONSE TO APPLICANT'S ANSWER TO BOARD QUESTION A2

The applicant's response to this question provides some very pertinent observations concerning the prupose of the criterion. The references to GDC-24 and 39 which were issued on July 10, 1967 as the forerunners of the present day GDC-17 provide an excellent vehicle for demonstrating the evolution of our present day requirements. However, I believe the evolution of GDC-17 is not quite as straightforward as one could infer from the applicant's testimony. I have provided Table A2 (attached) as a direct comparison of GDC-17 and the previous GDC-24 and 39 of 1967. Referring to Table A2, I have identified two major changes and one major addition from the 1967 GDC.

The first major change noted in Table A2 concerns the onsite power system. General Design Criterion 39 (1967) applied a single active failure criterion to the onsite power system. The problem with this requirement was that an active or passive component in an electrical system is no where near as easily defined as an active component in a mechanical system. The most notable analogy is probably piping in the mechanical system and cabling in the electrical system. Piping is assigned an American Society of Mechanical Engineers (ASME) code classification based upon what system in which it will be used. The end result of this classification process is a fully documented qualification of the piping. Once qualified by this process, the piping is considered a passive element in the mechanical system. There is no analogous classification process for cabling. Realizing this problem, the staff subsequently amended the definition of single failure in 10 CFR 50 Appendix A to reflect the position that both active and passive components should be included in the single failure analysis of electric systems. The staff also revised the General Design Criteria to reflect the requirement for a fully single-failure-proof onsite power system. This change placed more conservative criteria on the onsite power system.

The second major change noted in Table A2 is essentially the same evolution process of requirements for the offsite power system as discussed above for the onsite power system. However, recognizing the differences between onsite and offsite power systems, the evolved requirements for those two systems are quite different. Again, the single-active-failure requirement did not fit electrical systems. Whereas the evolution of requirements for the onsite power system are contained in the last four words of paragraph 2 of GDC-17 (i.e. "assuming a single failure"), the evolution of requirements for the offsite power system comprise the entire third paragraph of GDC-17.

A single-failure-proof offsite power system is neither attainable nor within the purview of the NRC. Faced with these realities and the ambiguity of the single-active-failure requirement; the staff provided an explicit description of what is required as a minimum of the offsite power system (i.e. GDC-17, paragraph 3). This evolution of requirements for the offsite power system is much more realistic than the original single-active-failure requirement.

The major addition noted in Table A2 is paragraph 4 of GDC-17. This paragraph introduces the requirements for transient and steady-state stability studies which demonstrate the ability of the onsite and offsite power systems to withstand system pertabations and requirements for the minimum of two offsite power lines to react and perform independently of one another.

The above described changes and additions from the 1967 criteria to present criteria significantly improved, clarified, and strenghened the requirements for electric power systems. In summary, the Board's interpretation of GDC-17 would require a single-failure-proof offsite power system. Clearly this is not the intent of GDC-17 as it has evolved over the years.

TABLE A2

Comparison of Present GDC 17 With 1967 Versions of GDC 24 & 39

GDC 17	GDC 24 & 39 (1967)	Comments
Criterion 17—Electric power systems. An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety.	GDC 24 (all)	Straight forward
The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.	GDC 39 (2nd sentence)	Minor changes
The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to	GDC 39 (1st sentence)	Straight forward
perform their safety functions assuming a single failure.	GDC 39 (2nd sentence - onsite)	Major change
Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.	GDC 39 (2nd sentence - offsite)	Major change
Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.	New	Major Addition

B. FAILURE OF OFFSITE POWER WITH SIMULTANEOUS ONSITE POWER FAILURE

B1. As [illegible] see it, the likelihood of loss of [illegible] AC power [illegible] may be expressed [illegible] the product of two factors: [illegible] probability [illegible] there will be an offsite power failure involving the [illegible] network generally or the Midway substation in particular and a resulting loss of station power -- which probability seems based on historical events, to lie in the range 1.0 to 0.1 per year; and (2) the probability that neither of the two onsite AC power systems (diesel generators) will start. The probability that any one diesel generator will fail to start on demand is taken by the staff to be one per hundred demands, i.e., 10^{-2} 25/.

If these figures are accurate, then the combined probability for the "loss of all AC power" scenario is in the range 10^{-4} to 10^{-5} per year. 26/ In this regard, the staff's Standard Review Plan for Nuclear Power Plants sets forth numerical guidelines for determining whether an event "resulting from the presence of hazardous materials or activities in the vicinity of the plant" should be considered in designing the plant (i.e., whether it is a "design basis" event). 27/ Under these guidelines, events with a realistically calculated probability value of at least 10^{-7} per year (or 10^{-6} per year for a conservative calculation) must be so considered.

The "loss of all AC power" sequence is not precisely within the category of events contemplated by the Standard Review Plan. However, its ultimate result -- assuming that power is not timely restored -- is an unprotected loss of coolant accident, the consequences of which are likely to exceed the guidelines of 10 CFR Part 100. We do not understand why this sequence of events (i.e., loss of offsite power combined with failure of diesels to start), which appears to have a probability well above the guideline values, should not be taken into consideration in the design of the plant. 28/ The parties are to address this point, setting forth their reasons for adhering (if they do) to a contrary position.

25/ Fitzpatrick Affidavit of June 12, 1978, p. 4. Also see Regulatory Guide 1.108, Section B.

26/ This conclusion further assumes that the failure of two diesel generators to start would be statistically independent events, an assumption which leads to the lowest likelihood of combined failure, and which might be nonconservative if there exists the potential for common failure modes for the onsite systems.

27/ NUREG 75/087, Section 2.2.3, paragraph II.

28/ We have accepted the Standard Review Plan guideline values as reasonable in another case. Public Service Electric and Gas Company (Hope Creek Units 1 and 2), ALAB - [illegible])

STAFF RESPONSE TO BOARD QUESTION B1

The NRC staff has not applied the above referenced numerical reliability goals to the station blackout scenario. This scenario has recently been identified as Task Action Plan (TAP) A-44 and it is expected that numerical reliability goals will be established as a result of this program in much the same manner as was done for anticipated transients without scram. Because this task action plan is in its initial stages of development, no criteria have been established. We have therefore adopted the 10^{-7}/year goal referenced above by the Appeal Board in anticipation of the results of TAP A-44 and have required the applicant to demonstrate that this goal can be met by the St. Lucie Unit 2 design.[4/]

STAFF RESPONSE TO APPLICANT'S ANSWER TO BOARD QUESTION B1

The applicant's answer provides an analysis of probability of ac power restoration verses time following a station balckout. In our review of this analysis, we found an apparent discrepancy between the Florida Power & Light historical data and the constant used in the probability equation specifically, in response to Board Question B3, the applicant demonstrates an average duration of 26 minutes for its loss of offsite power events. The applicant then proceeds to use 1.6 hr^{-1} as the constant in the probability equation. This constant represents an average duration of 37.5 minutes which is conservative based upon the historical data. The 26 minutes would yield a constant equal to 2.3 hr^{-1}. We were informed by the applicant that the 37.5 minute figure used represented one standard deviation on the data base for conservatism.

4/ Siegel Testimony, September 21, 1979.

Use of the 2.3 hr^{-1} time constant reduces the applicant's figure of 3.6 hours to meet the 10^{-7}/year goal to 2.7 hours. If we use the conservative estimates of diesel generator unreliability used in the Reactor Safety Study (i.e. 3×10^{-2}) and the 2.3 hr^{-1} restoration time constant, the time period becomes 3.5 hours (essentially the figure presented by the applicant). The significance of these time periods is that if it can be demonstrated that natural circulation of the primary system can be maintained for at least the time period calculated, the probability of core damage due to the station blackout scenario will remain below 10^{-7} per year. From the above calculations, if the applicant can demonstrate primary system integrity (i.e. natural circulation with no excessive leakage) for four hours of station blackout conditions, the probability of core damage is well below the 10^{-7}/year goal for the St. Lucie 2 design.

B2. In line with the above discussion, the testimony is to analyze events that would occur between the "loss of all AC power" and the violation of either the fuel design limits or the design conditions of the reactor coolant pressure boundary (or any portion thereof). In particular, the parties should, if possible, reconcile their differing responses to question B.1(b) of our March 10, 1978 order,[29/] or, if not, point up precisely where the disagreements lie.

29/ (References fn 24 reproduced below:)

The staff's judgment is that the first failure would be that of a primary pump seal, at about one hour after the loss of AC power -- resulting in a small loss of coolant accident. (Fitzpatrick Affidavit of June 12, 1978, p. 11).

STAFF RESPONSE TO BOARD QUESTION B2

My affidavit filed in response to the Appeal Board's order of March 10, 1978 gave the applicant credit for one hour following the loss of all ac power prior to the onset of [illegible]

credit was taken from the applicant's PSAR section 9.2.2.3.1 which demonstrates

reactor coolant pump seal integrity for an hour of operation following loss of component cooling water. The staff recognized the conservatism involved in equating the dynamic conditions of the pump running verses the static conditions of the pump stopped. However, in the absence of direct test results for the static condition encountered during station blackout, the staff was unwilling to attempt to extrapolate from the applicant's analysis. This remains the staff position.[5/]

STAFF RESPONSE TO APPLICANT'S ANSWER TO BOARD QUESTION 2

The applicant notes that Unit 1 diesel generator can be aligned to Unit 2 safety busses and estimates that two men could effect realignment of one diesel generator in about one hour. The applicant has not taken any credit for this capability in his analysis of probability verses time for restoration of power to Unit 2 following a station blackout. However, prior to the completion of TAP A-44, it is not clear what credit the staff could give for this design feature.

Station blackout at multi-unit sites should be analyzed in depth prior to determining the criteria governing reassignment of onsite power sources. Such an undertaking must be part of a comprehensive effort which in this case is TAP A-44. Beyond this, the site specific situation of requiring two man hours of effort to effect the transfer introduces operator error as a factor in the probability of failure to restore power. Also, the applicant's probability calculations assume that the two Unit 2 diesel generators and restoration of offsite power are being worked on simultaneously. The additional two men required for transferring one diesel generator from Unit 1 to Unit 2 would certainly tax the available onsite manpower.

5/ Siegel testimony, September 21, 1979.

In summary, the capability of transferring diesel generators between units is a very desirable design feature especially for the Unit 2 blackout scenario. However prior to completion of TAP A-44, it is not clear how much credit the staff could give for this design feature.

B3. The testimony should contain a discussion, supported by such data as is available, related to the time that might be required to start a diesel generator assuming it failed to respond to the initial, auto-start signal.

STAFF RESPONSE TO BOARD QUESTION B3

The staff does not have an independent data base in order to calculate a mean-time-to-repair (MTTR) for the diesel generators in nuclear service. The Licensing Event Reports (LERs) submitted in accordance with the guidelines of Regulatory Guide 1.16 "Reporting of Operating Information - Appendix A Technical Specifications" have not required MTTR data for diesel generator failure reports. Therefore, if MTTR data had been included in any LER on diesel generator failure, it would have been because the licensee volunteered such information.

Regulatory Guide 1.108 "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (October 1976) established the requirement to report duration of outages from which MTTR can be calculated. This regulatory guide applies to all construction permit applications following its data of issuance. No operating nuclear plants fall into this category.

The Regulatory Requirements Review Committee (R^3C) reviewed Regulatory Guide 1.108 and decided that it should be considered for backfitting to operating reactors on a case by case basis. The staff has since followed this policy decision and some operating plants have been required to meet the requirements of this guide. The number of plants involved are not sufficient to yield a statistically meaningful data base and additionally. the outage time reporting requirement applies to current failures only not previously reported failures.

[illegible]

The applicant's deletion of certain diesel generator failures due to corrective design measures is appropriate and there is merit to the argument that use of historical data for returning a diesel generator to service is conservative as no undue time-pressure constraints existed.

B4. Finally, in the light of the discussion of points 2 and 3 above, the parties are to review possible measures for decreasing the likelihood of exceeding design limits on the reactor fuel and pressure boundary under the assumption that there is some time available to activate an auxiliary power source subsequent to a total loss of AC power.

STAFF RESPONSE TO BOARD QUESTION B4

The limiting event following station blackout is loss of national circulation in the primary coolant system (i.e., loss of core cooling capability). Loss of natural circulation is brought about by a significant loss of primary coolant which would escape through the reactor coolant pump seals. If the leak rates through the seals can be shown to provide at least four hours before sufficient inventory is lost to stop natural circulation; the probability of

be shown to provide at least twenty four hours. Before sufficient inventory is lost, the probability of loss of natural circulation is negligible and the first dependent failure (assuming ac power has not been restored) would then become the loss of capacity in the station batteries. This failure would take away the operator's ability to control the auxiliary feedwater system and all intelligence on the plant status.

STAFF RESPONSE TO APPLICANT'S ANSWER TO BOARD QUESTION B4

Upon demonstration of at least four hours of natural circulation following station blackout, the staff concurs with the applicant's answer that the potential for exceeding design limits on the reactor fuel and pressure boundary is acceptably low.

C. SYSTEM RELIABILITY DURING ALERT STATUS

According to the staff, the applicant is being required to define conditions in which it will put its power distribution system in an "alert status".30/ At such times, loss of offsite power would presumably be more likely than normal. We wish to be advised as to the existence of measures that might be taken to assure, or at least to increase, the reliability of the onsite power systems during an "alert status" period.

30/ Fitzpatrick Affidavit of June 12, 1978, Enclosure 3.

STAFF RESPONSE TO BOARD QUESTION C

The staff concurs with the applicants' answer to this question in that the diesel generator could be manually started in anticipation of a loss of off-site power. In fact, the staff has enforced such a requirement in the techni-cal specifications [illegible] requires the weighing of many factors and must be arrived at on a case by by case basis. Many diesel generator designs including those at St. Lucie cannot be run unloaded (i.e. at idle) for extended periods of time. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons, and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequence of no load or light load operation are potential equipment failure due to the gum and varnish deposits and fire in the engine exhaust system.

Another factor to be considered is that "alert states" on a power system could happen relatively frequently. Most often the alert state would not be of long duration and could be terminated, for example, by startup of another generating unit or units thus reverting the system back to a "normal state". Once in a while the alert state will be terminated by another contingency event (such as loss of a critical transmission line) and the state of the system will go to an "emergency state" where at least part of the system has been lost. The above situation could place an undue number of challenges to the diesel generators where in retrospect most would have been unnecessary. In the instances where the staff has required the manual starting of onsite diesel generators, the underlying cause has usually been a specific item of concern such as an impending tornado.

The staff also concurs with the applicants conclusions that such measures are not required for St. Lucie. The bases for this conclusion are that no-load running of the diesel generators for every alert state that the grid system might enter could unnecessarily hamper their performance in a real emergency:

it would consume onsite personnel that could be doing other important functions; and the onsite power system is specifically designed to automatically start and perform its intended function in the presence of a single failure.

D. ONGOING IMPROVEMENT OF SYSTEM RELIABILITY

The testimony should provide a concise, up-to-date discussion of existing measures, or those planned for the near future, by which the reliability of the applicant's system may be enhanced. Particular attention should be paid to the seemingly excessive number of personnel errors which appear to have led to the May 14, 1978 outage and to have contributed to the May 16, 1977 disturbance.

STAFF RESPONSE TO BOARD QUESTION D

The applicant has and is continuing to upgrade and the reliability of the offsite power system in three major areas. These areas are 1) the strengthening of the power system (i.e. added generation, transmission, and system protection), 2) power system field personnel training and guidance, and 3) a centralized monitoring and control facility.

The 500 kv system additions addressed in the applicant's testimony provide a significant improvement in reliability, capability, and performance not only for St. Lucie via Midway Substation but for the entire southeastern Florida quadrant. The additional transfer capability afforded by these lines will allow the generation at St. Lucie, Martin, and the remainder of the system to flow into the Miami area upon loss of generation within this heavy load area. The lack of this transfer capability has been a significant contributor to a large percentage of the cascading grid disturbances that have originated in southern Florida.

The applicant's response to this question also addresses measures that have been taken to reduce field switching personnel errors. The two most notable features now in effect are that proposed system configurations are analyzed under contingency conditions prior to allowing the switching and field personnel are equipped with approved written procedures. The first feature is a result of the position taken by the staff requiring same.[6/] The second feature concerning approved written procedures marks what appears to be a major change in FP&L philosophy. At the June 5, 1978 meeting between the staff and FP&L on the May 14, 1978 loss of offsite power at St. Lucie, FP&L stated that written procedures for field personnel were not used and not considered of benefit. Both of these features (i.e. analysis and written procedures) are major improvements in FP&L operations.

The third major contributor to overall power system reliability is the now operational system dispatch and control center. As described in the applicant's testimony, this center provides the system dispatcher with a tremendously powerful tool to aid in the optimum operation and, on occasion, restoration of the power system. In order to utilize this control center to its full potential, extensive operator training is required. The applicant has purchased a training simulator and is conducting training programs for the operating staff. This complex and powerful tool can only be as effective as those who operate it. With properly trained personnel, the dispatcher confusion and lack of system status information that contributed to the May 16, 1977 grid disturbance are eliminated.

6/ Fitzpatrick affidavit, June 12, 1979, Enclosure 3 Staff Position No. 2

IV. CONCLUSION

The St. Lucie Unit 2 design conforms to the requirements of GDC 17. Upon demonstration by actual test results that the reactor coolant pump seals can endure station blackout conditions for four hours, it can be concluded that the probability of core damage due to a station blackout is below the Standard Review Plan 2.2.3 numerical reliability goal of 10^{-7} per year. The offsite power system will have undergone (prior to Unit 2 operation) major changes to significantly increase its overall reliability. The changes include the addition of a 500 kv transmission system which overlays the previous 240 kv system from the Midway substation south to the Miami area, increasing transfer capability with Georgia and therefore stronger ties during system disturbances, and a sophisticated centralized dispatch and control center. The staff conclusion of the acceptability of St. Lucie Unit 2 electric power systems remains unchanged.

ENCLOSURE 1

EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS
OF ROBERT G. FITZPATRICK

EDUCATION

B.S. Electrical Engineering, 1971; Northeastern University, Boston, Mass.

M.S. Electrical Engineering, 1972; Northeastern University, Boston, Mass.

Major: Electrical Power Systems Engineering

PROFESSIONAL QUALIFICATIONS

From 1972 - 1974 I worked for Yankee Atomic Electric Company in Westboro, Massachusetts. I was assigned to the Electrical and Control Engineering Group and my duties included work on the Yankee operating nuclear plants and the Seabrook Project. (Prior to this-I spent 3 years with Yankee as a cooperative education student while attending Northeastern University).

From 1974 to the present I have worked for the Nuclear Regulatory Commission involved in the technical review of electrical systems (onsite and offsite power, and instrumentation and control). Through 1976 I was a member of the Electrical Instrumentation and Control Systems Branch. This Branch was split in January 1977 into an I&C branch and a power branch. Since this split I have been a member of the Power Systems Branch. My present title is Senior Reactor Systems Engineer (Electrical). Following the Three Mile Island accident, I have been assigned to the Three Mile Island Site Support Group.

I am a member of the IEEE and also represent the NRC as a member of IEEE Nuclear Power Engineering Committee Subcommittee 4 "Auxiliary Power Systems". This [illegible]

ENCLOSURE 2

Selected Sections of Standard Review Plan 8.2
Concerning Physical Independence of Offsite Power Circuits

I. AREAS OF REVIEW

The offsite power system is referred to in industry standards and regulatory guides as the "preferred power system." It includes two or more identified power sources capable of operating independently of the onsite or standby power sources and encompasses the grid, transmission lines (overhead or underground), transmission line towers, transformers, switchyard components and control systems, switchyard batters systems, the main generator, and disconnect switches, provided to supply electric power to safety-related and other equipment.

The PSB will review the following features of the preferred power system.

1. The preferred power system arrangement is reviewed to determine that the required minimum of two separate circuits from the transmission network to the standby power distribution system is provided. In determining the adequacy of this system, the independence of the

two (or more) circuits is examined to see that both electrical and physical separation exists so as to minimize the chance of simultaneous failure. This includes a review of the assignment of power sources from the grid, location of rights-of-way, transmission lines and towers, transformers, switchyard interconnections (breakers and bus arrangements), switchyard control systems and power supplies, location of switchgear (in-plant), interconnections between switchgear, cable routings, main generator disconnect, and the disconnect control system and power supply.

II. ACCEPTANCE CRITERIA

In general, the preferred power system is acceptable when it can be concluded that two separate paths from the transmission network to the standby power distribution system are provided in accordance with General Design Criterion 17; adequate physical and electrical separation exists; and the system has the capacity, capability, and reliability to supply power to all safety loads and other required equipment.

Details of the application of the acceptance criteria to the areas of review described in subsection I are as follows:

1. System Design Requirements

   a. General Design Criteria 33, 34, 35, 38, 41 and 44 set forth requirements for the safety systems whose source of power is system redundancy shall be such that, for preferred power system operation (assuming standby power is not available), the system safety function can be accomplished assuming a single failure. To utilize this requirement, the single failure is assumed to occur downstream of the preferred power feed breakers at the safety buses, i.e., in the safety-related distribution system. The acceptability of the preferred power system design in this regard is based on its conformance with General Design Criterion 17 and its capability to supply the redundant safety components and systems required by these General Design Criteria.

b. General Design Criterion 17 requires two physically independent circuits from the offsite grid, one of which is designed to be available within a few sections following a loss-of-coolant accident.

III. REVIEW PROCEDURES

To assure that the requirements of General Design Criterion 17 are satisfied, the following review steps should be taken (as applicable for a CP or OL review):

a. The electrical schematics should be examined to assure that at least two separate circuits from the transmission network to the standby power distribution system buses are provided (a switchyard may be common to these paths).

b. The routing of transmission lines should be examined on the station layout drawings and verified during the site visit to assure that at least two independent circuits from the offsite grid to the safety-related distribution buses are physically separate and independent. Preferably these lines should enter the station on separate rights-of-way, ideally on opposite sides of the switchyard, should leave the switchyard on opposite sides, and should terminate at transformers located on opposite sides of the reactor or turbine building. No other line should cross these two circuits. As physical separation becomes less than the ideal, attention should be directed towards assuring that no single event such as a tower falling or a line breaking can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from being exceeded.

c. As the switchyard may be common to both circuits from the offsite grid to the safety-related distribution buses, the electrical schematics of the switchyard breaker control system and power supply and the breaker arrangement itself should be examined for the possibility of simultaneous failure of both circuits from single events such as a breaker not operating during fault conditions, loss of a control circuit power supply, etc.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY & LICENSING BOARD

In the Matter of:	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
(St. Lucie Nuclear Power Plant, Unit No. 2)	))	

Testimony of
Edward J. Fowlkes
September 21, 1979

Testimony of
Edward James Fowlkes

Relating to
ASLAB Memrandum and Order of

April 5, 1979, on

Electrical Grid Stability and Emergency Power Systems

(Question B1 - Failure of Offsite Power)

My name is Edward James Fowlkes.

I am a Supervisory Electrical Engineer serving as the Chief, Interconnection & Special Investigations Branch in the Federal Energy Regulatory Commission's Office of Electric Power Regulation/ Division of Interconnection and Systems Analysis. My education and professional qualifications statement is attached to this testimony and herein incorporated by reference.

SCOPE OF TESTIMONY

The purpose of this testimony is to address Question B1 as stated in the Atomic Safety and Licensing Appeal Board Memorandum and Order of April 5, 1979, a statement of which is provided in my accompanying Affidavit.

Offsite Power Supply to the St. Lucie 1,579 MW Nuclear Plant From the Midway 500/230/138 kV Substation Evaluation

Presently and in 1983, the proposed operational date for the St. Lucie No. 2, 802 MW, nuclear unit, there are three heavy duty, (952 MVA) conservatively designed 230 kV lines, respectively 11.62, 11.77 and 11.75 miles in length. A breaker-and-a-half 230 kV circuit breaker arrangement is used to terminate the lines at both ends and in no case are the lines in the same three-breaker bay. At Midway Substation, excluding the St. Lucie 230 kV lines, there will be one 500 kV line, via a 500/230 kV 1,500 MVA FOA auto transformer with two low-side circuit breakers; five 230 kV lines, and two 138 kV line, connected via two 230/138 kV 224 MVA auto transformers. Specifically these lines are (Ratings in parenthesis):

Length	Terminations	Voltage
26.4	Midway - Martin (2,650 MVA)	500 kV
53.74	Midway - Malabar No. 1 (387 MVA)	230 kV
50.39	Midway - Malabar No. 2 (387 MVA)	230 kV
	(These two lines are on a common Right-of-Way north to Malabar substation)	
53.31	Midway - Indiantown - Pratt & Whitney - Ranch (840 MVA)	230 kV
53.26	Midway - Ranch (773 MVA)	230 kV
	(These two lines utilize a common Right-of-way south to the Ranch Substation)	
47.9	Midway - Sherman - Martin 230 kV Indiantown (420 MVA) 230 kV	
	Midway - Plumosus (178 MVA)	138 kV
7.33	Midway - Hartman (City of Fort Pierce)	138 kV

These lines will provide eight sources (over four transfer paths) of FP&L system and other Peninsula Florida system supply of offsite power to the Midway - St. Lucie substation. The 230 kV lines terminate at Midway and St. Lucie in four substation bays arranged in a breaker-and-a-half protective scheme. To disconnect one line's terminal, two circuit breakers must open. Should one of the two breakers fail to clear, at most one line (generator at St. Lucie) would be disconnected from service. If a bus side associated line breaker fails to clear, the associated bus will be cleared, however, this would not affect the continuity of any other line (generator at St. Lucie) except the faulted line initiating protective relay action. For all double contingency (n-2) possibilities at the Midway substation, at most one Midway to St. Lucie 230 kV line's operation is affected and at least six line sources remain to Midway and at least two 230 kV lines to St. Lucie. Midway substation double contingencies considered were:

(1) 230 kV or 138 kV line fault with bus side breaker failure;
(2) 230 kV or 138 kV line fault with mid-bay (not adjacent to bus) failure;
(3) 500 kV line fault with stuck breaker;
(4) 230/138 kV bus fault with breaker failure;
(5) 500 kV bus fault with breaker failure:
(6) double 230 kV line or 500 kV plus 230 kV line fault; and,
(7) double 230/138 kV bus fault.

These outage conditions are within the scope (SERC & FCG Planning Criteria) of those normally considered to provide an adequate bulk power supply system. In normal utility system operation, all facilities operational, the double contingency would be caused by the simultaneous failure of two components, however, this condition could also evolve from the unscheduled (forced) outage of one during the scheduled (maintenance) outage of another.

Even with a triple contingency(n-3), excluding the loss of all three Midway to St.Lucie 230 kV lines, at the Midway substation, a highly unlikely event not normally considered as a design event, 3 to 4 230 kV lines (depending on which mid-bay breaker fails to clear) remain connected to the Midway substation and 2-3 230 kV lines continue operation between Midway and St Lucie.

Therefore, it may be concluded that, short of a sustained loss of all Midway to St. Lucie 230 kV lines, the loss of all Midway supply lines and thence all offsite St. Lucie plant supply is an event substantially beyond normal electric utility design criteria.

It would require the simultaneous occurrence of more than three disabling events at Midway substation or system collapse, including a disturbance event causing the islanding and loss of generation to the FP&L Midway substation to cause the complete loss of all offsite power to St. Lucie. Short of the destruction of the Midway substation, eight essentially independent transmission failure events must occur to lose Midway substation.

To quantify the approximate failure frequency of transmission supply to the Midway and St. Lucie substation, a limited scope transmission reliability assessment was made of the transmission system supplying Midway substation through to the St. Lucie 230 kV substation. To simplify calculations, the following assumptions were made:

(1) Circuit breaker, relay, bus and transformer failure events were not included. This was partially because no source of 500/230 kV transformer failure rates and repair times was available. A bus fault concurrent with a break failure must occur to affect a line.

(2) While the Midway – Malabar 230 kV lines and the Midway – Ranch and Midway – Indiantown – Ranch 230 kV lines occupy common right-of-ways, failure independence was assumed;

(3) The failure event improvement provided by the 138 kV lines (Midway - Plumosus and Midway - Hartman) was excluded;

(4) Because of the sparsity of line failure event data provided by FP&L, 230 kV line failure rate and repair characteristics in Institute of Electrical and Electronics Engineers (IEEE) publication on transmission system reliability calculations were used (Vol. PAS-87, No. 3, March 1968, "A Method for Calculating Transmission System Reliability" Stephen A. Mallard and Virginia C. Thomas - Table I). The Transmission Interruption Summary provide by FP&L only covered the few 230 kV Midway substation line (138 kV also provided) failures that occurred during the 1975-1978 period. System outages are not incorporated in the data base.

(5) The 230 kV line failure rate (outages per unit per year) used was the weighted average of forced normal weather and forced adverse weather outages. The impact of the adverse weather component (152.63 times the normal component) was incorporated based up U.S. Department Commerce/Weather Bureau/Climatological Services Division data provided in Technical Paper No. 19, "Mean Number of Thunderstorm Days in the United States", September 1952 which showed Miami, Florida with a mean annual number of thunderstorm days of 91. Therefore, the adverse weather failure rate component was given a 25% weight. The 230 kV line failure rate used was 0.1105915 outages per mile-year consisting of normal and adverse weather components respectively of 0.00285 and 0.435. The normal and adverse

weather repair times respectively were 4.43 and 15.2 hours which when weighted accordingly provided an equivalent repair time of 7.115 hours. Failure rates calculated with the FP&L 230 kV data varied between 0.0 and 6.25 per year with most about 0.5 per year (0.01 outages/mile-year for 50 mile line)

(6) The same failure rate (230 kV) was used for the Midway - Martin 500 kV line

(7) Scheduled outage and overloads due the outage of another facility effects were not included.

Following are the line failure rates (outages per year) used in the calculations. The component repair time was 7.115 hours for all lines.

	Line Terminations	Outages Per Year
1.	Midway - Malabar No. 1, 50.39 miles	5.5727
2.	Midway - Malabar No. 2, 53.74 miles	5.9432
3.	Midway - Martin 500 kV, 26.4 miles	2.9196
4.	Midway - Sherman - Martin 230 kV - Indiantown, 47.9 miles	5.2973
5.	Midway - Indiantown, 24.12 miles	2.6675
6.	Indiantown - Pratt & Whitney - Ranch, 29.19 miles	3.2282
7.	Midway - Ranch, 53.26 miles	5.8901
8.	Midway - St. Lucie No. 1, 11.62 miles	1.2851
9.	Midway - St. Lucie No. 2, 11.77 miles	1.3017
10.	Midway - St. Lucie No. 3, 11.75 miles	1.2995

Lines 4. and 5. were considered as a parallel combination in series with Line 6. This result was taken as a parallel combination with Lines 1., 2., 3., and 7. to Midway substation, resulting in a combined unavailability of all lines and failure frequency (events per year) respectively of 652.2066 x 10^{-15} and 4.0178 x 10^{-9} events per year (Mean Time Between Failures (MTBF) of 248,890,300.4 years).

Lines 8., 9., and 10. were combined in parallel with this combination taken in series with the above to St. Lucie 230 kV substation. The resultant unavailability of all lines, failure frequency and MTBF respectively were 1.1653 x 10^{-9}, 4.3058 x 10^{-6} events per year and 232,244.79 years. These results apply only to the specified transmission line components without consideration of generation being available to supply the lines.

Attachment Nos. 2 and 3 discussion design considerations as they apply and are used in Peninsula Florida and the FP&L interconnections with other Peninsula Florida systems.

REFERENCES

1. 1978 Power System Statement (FPC Form No. 12) from Florida Power & Light Company

2. 1978 Power System Statement from Florida Power Corporation

3. 1978 Power System Statement from Tampa Electric Company.

4. April 1, 1979, Coordinated Bulk Power Supply Program, 1979-1998 from Sosutheastern Electric Reliability Council.

5. April 1, 1978, Bulk Power Supply Program, 1978-1997 from Southeastern Electric Reliability Council.

6. August 1, 1979, 1979 Ten-Year Plan-State of Florida-Electrical Generating Facilities and Associated Transmission Lines, Florida Electric Power Coordinating Group.

7. March 1979, Report of Special Transient Stability Study for 1978 Summer Peak, to the System Planning Committee by the Special 1978 Transient Stability Task Force.

8. January 1979, Transmission Loadflow Analysis Report - 1982 & 1987 Summer Periods by Florida Electric Power Coordinating Group, System Plannng Committee, Transmission Task Force.

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15. Transient Stability Evaluation of the Impact of the New 230 kV Tie Between FP&L and Georgia Power Company, Florida Power & Light Company, August 31, 1979

16. Review of the Performance of Various Electrical Configurations between St. Lucie Plant and the FPL Grid, Florida Power & Light Company, August 31, 1979

17. Testimony of Frederick George Flugger relating to ASLAB Memorandum and Order of April 5, 1979, on Emergency Grid Stability and Emergency Power Systems (Questions A2, B1, B2, B3, and B4 of ALAB 537) June 22, 1979.

18. Joint Testimony of Michel P. Armand, Ernest L. Bivans, and Wilfred E. Coe Relating to Questions A1 and D of ALAB 537. June 1, 1979

Edward J. Fowlkes
Professional Qualifications Statement

My name is Edward J. Fowlkes. I am Supervisory Electrical Engineering, serving as the Chief, Interconnection & Special Investigations Branch in the Federal Energy Regulatory Commission's Office of Electric Power Regulation/Division of Interconnection and Systems Analysis. The ISI Branch analyzes and evaluates: (1) transmission, interconnection and operational characteristics of electric power systems associated with FERC, or other proceedings and investigations upon request; (2) FERC licensing jurisdiction over electric transmission lines associated with hydroelectric projects; and, (3) benefits available through increased coordination and pooling of electric power systems. Prior to my Federal employment beginning in 1971 with FERC's predecessor the Federal Power Commission/Bureau of Power/Power Supply & Reliability Division, I was employed by the Central Hudson Gas & Electric Corp., in Poughkeepsie, New York.

I received a Bachelor of Science Degree in Electrical Engineering (Power Option) in 1964 from Howard University in Washington, D.C. and a Master of Enginering Degree in Electric Power Engineering in 1971 from Rensselaer Polytechnic Institute in Troy, New York. In 1968-69, I attended the General Electric Company's Power System Engineering Course in Schenectady, New York. I am a registered Professional Engineer in the State of New York and a member of the Institute of Electrical and Electronics Engineers.

Attachment No. 1

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In The Matter Of:	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
(St. Lucie Nucler Power Plant,	)	
Unit No. 2)	)	

AFFIDAVIT OF EDWARD J. FOWLKES

I am Edward J. Fowlkes, Chief, Interconnection & Special Investigations Branch for the Federal Energy Regulatory Commission's Office of Electric Power Regulation/Division of Interconnection and Systems Analysis. My education and professional qualifications appear as an attachment to this testimony. I am participating here at the request of the U.S. Nuclear Regulatory Commission's Counsel for the NRC staff to provide assistance in their assessment of the adequacy of the Florida Power & Light Company and the Peninsula Florida transmission system for the offsite emergency power requirements of the 802 MW St. Lucie No. 2 nuclear unit.

The purpose of this affidavit is to respond to Question B1 concerning the failure of St. Lucie nuclear plant offsite power in the Atomic Safety and Licensing Board Memorandum and Order of April 5, 1979 (ALAB-537).

<u>QUESTION B1</u>

As we see it, the likelihood of loss of all AC power at St. Lucie may be expressed as the product of two factors: (1) the probability that there will be an offsite power failure involving the FPL network generally or the Midway substation in particular and a resulting loss of station power — which probability seems based on historical events, to lie in the range 1.0 and 0.1 per year; and (2) the probability that neither of the two onsite AC power systems (diesel generators) will start. The probability that any one diesel generator will fail to start on demand is taken by the staff to be one per hundred demands, i.e., 10^{-2} 25/.

If these figures are accurate, then the combined probability for the "loss of all AC power" scenario is in the range 10^{-4} to 10^{-5} per year. 26/ In this regard, the staff's Standard Review Plan for Nuclear Power Plants sets forth numerical guidelines for determining whether an event "resulting from the presence of hazardous materials or activities in the vicinity of the plant" should be considered in designing the plant (i.e., whether it is a "design basis" event). 27/ Under these guidelines, events with a realistically calculated probability value of at least 10^{-7} per year (or 10^{-6} per year a conservative calculation) must be so considered.

The "loss of all AC power" sequence is not precisely within the category of events contemplated by the Standard Review Plan. However, its ultimate result — assuming that power is not timely restored — is an unprotected loss of coolant accident, the consequences of which are likely to exceed the guidelines of 10 CFR Part 100. We do not understand why this sequence of events (i.e., loss of offsite power combined with failure of diesels to start), which appears to have a probability well above the guideline values, should not be taken into consideration in the design of the plant. 28/ The parties are to address this point, setting forth their reasons for adhering (if they do) to a contrary position.

25/ Fitzpatrick Affidavit of June 12, 1978, p. 4. Also see Regulatory Guide 1.108, Section B.

26/ This conclusion further assumes that the failure of two diesel generators to start would be statistically independent events, an assumption which leads to the lowest likelihood of combined failure, and which might be nonconservative if there exists the potential for common failure modes for the onsite systems.

27/ NUREG 75/087, Section 2.2.3, paragraph II.

28/ We have accepted the Standard Review Plan guideline values as reasonable in another case. Public Service Electric and Gas Company (Hope Creek Units 1 and 2), ALAB - 429, 6 NRC 229 234 (1977).

I, Edward J. Fowlkes, being first duly sworn, depose and say that statements of this affadavit are true to the best of my knowledge and belief, and that if asked questions thereon, my answers in response thereto would be as contained herein.

Edward J. Fowlkes

Edward J. Fowlkes

Washington, D.C.)

Subscribed and sworn to before me this 21st day of September, 1979.

Notary Public

My Commission Expires July 1, 1982

Discussion of the Bulk Electric Power Supply Planning and Design Program

All of the following contingency analysis tests are incorporated in the FP&L and Peninsula Florida systems bulk electric power suppply planning and design process. While extensive FGC studies of the 1983 Peninsula Florida system have not been performed because of the tentative nature of area utility plans, such studies, I have been informed, are planned to be completed by early 1980.

In the process of designing the bulk power supply facilities, generation and transmission, the power system is analyzed at peak as well as lower load conditions. In the case of Peninsula Florida systems such analysis is done on an individual utility basis as well as a Peninsula Florida basis (Florida Electric Power Coordinating Group). Once the level of generation needed is established, the transmission system must be analyzed to provide an adequate means for transferring the supply to the load (MW and MVAR). The transmission system design must be thoroughly coordinated with the generation expansion program and visa versa.

Establishment of an adequate transmission system must consider both normal and unusual conditions both of the available generation and of the transmission system. Compounding this analysis are the ever present possibilities that a planned generation or transmission facility will not be available as planned (institutional, environmental or other regulatory delay). The abnormal design conditions evaluated seek to account for scheduled outages (generation, transmission line or substation maintenance) and forced (unscheduled) outages of generation or transmission facilities. Such analysis is performed through use of load flow and stability computer programs.

Load flow is used to determine the distribution pattern of the electric power throught the transmission system and losses with a specified generation schedule (economic dispatch and spinning reserve allocation) and unit availability, system load level (MW) and transmission facility availability. Such analysis will determine if with specified availability of facilities, at a specific system load level, whether the transmission system components operating within their capability limits (MVA) and voltage limits. The spectrum of situations analyzed would include:

<u>Base Case</u> (all generation and transmission facilities available)

A. Peak Load
B. Lower Load Level

<u>Single Contingency</u>

A. Single line outage
B. Single generator outage

<u>Double Contingency</u>

A. Double line outage (generally restricted to a double-circuit transmission line outage or two single-circuit lines on a common right-of-way)

B. Double generator outage (this would account for situations where a unit was scheduled out and another unit had to be taken off line where both units may not be at the same site and where the second unit was not lost due to fault or sudden trip).

C. Single line outage and generator outage (this would account for conditions wherein a line or generator was scheduled out and a line or generator was forced out of service)

D. Other Multiple Outages (outages of more than two bulk power supply facilities may be considered depending on anticipated area or regional conditions but are not generally design criteria)

Area Transfer Capability

A. Intra system transfer capability (to determine the capability to transfer power from one utility system subarea to another. Such analysis 14. may be useful in developing restoration plans and in determining limiting facilities)

B. Inter system transfer capability (to determine the import or export capability between utility systems or regions)

The preceeding contingencies are evaluated both at peak and lower load conditions in the process of analyzing the bulk power supply system adequacy and its adherence to design criteria. In all cases, it is presumed that if a facility or facilities are outaged because of a fault condition, the system is transiently stable and the effect of interconnected utility systems are represented through appropriate model equivalents. These load flow contingency studies are also performed as a routine part of normal system operation's periodic security analysis via on-line load flows at modern system operations control centers, for each capability period-summer and winter, on the mid range system plan 3-7 years in future and on the longer-range system 9-15 years in the future. The extensiveness of the contingency testing will depend on the study requirements and reasons precipitating the particular study. The stability of the system(s), the ability to survive major disturbances without uncontrolled losses of generator or load and without system collapse, is determined through transient stability modelling.

Transient stability programs are design to evaluate electric power system dynamics resulting from sudden losses of bulk power supply facilities and loads due to faults or other sudden contingencies. These may include:

<u>Loss of Generation</u>

A. Outage of a critical transmission line caused by a fault.

B. Outage of a critical transmission line caused by a fault during the scheduled outage of another critical line.

C. Sudden loss of all lines on a common right-of-way (this could include the unlikely loss of three or more lines occupying a common right-of-way).

D. Delayed clearing of a fault at any point on the system due to failure of a circuit breaker to open (this accounts for system dynamics that may result if the primary protective relay system dynamics that may result if the primary protective and the back-up protective relaying and associated circuit breaker(s) must operate to clear the fault)

E. Sudden loss of a substation plus transformation including any generating capacity connected thereto. The substation loss, from a practical view point would be limited to a single voltage level at a multivoltage level substation.

The evaluation of the foregoing events would be directed towards the transient analysis of the power system(s) and would model the generator, load and protective relay dynamic performance to verify that no uncontrolled system separations, loss of generation, facility overloads or system collapse occurs. Also modelled would be the performance of underfrequency relay response consonant with encountered situations. The fact that the analysis shows that underfrequency relays operate as planned is an appropriate result dictated by the extent transmission and generation supply. The analysis may also be used to develop the appropriate underfrequency relay load shedding scheme.

<u>Florida Peninsula Design Criteria For System Planning and Operation</u>

The Florida Power & Light Company along with the other Florida Peninsula systems design their transmission facilities to meet the Florida Electric Power Coordinating Group (FCG) criteria which parallels the SERC Regional Criteria. The FCG planning criteria is for the operating systems in Florida is set out in the FCG Planning Handbook.

SERC Regional Criteria - the objective of the criteria is to assure that cascading outages do not result from any forseeable contingencies. Therein cascading is defined as the uncontrolled successive loss of system elements as a result of a contingency at any location. Cascading results in an uncontrolled, widespread collapse of system generation and load, which collapse cannot be restrained from subsequently spreading beyond a predetermined area through appropriate engineering models, (load flow and transient stability studies).

Pursuant to the SERC Regional Criteria, electric systems are to be planned to prevent cascading should any of the following contingencies occur:

1. Loss of Generation - the sudden loss of the entire generating capacity at any one plant.

2. Loss of Load - the sudden loss of a large load or major or major load center.

3. Loss of Transmission
   A. The outage of the most critical transmission line due to a three-phase fault concurrent with the outage of any other critical transmission line.
   B. The sudden loss of all transmission lines on a common right-of-way.
   C. The sudden loss of a substation (limited to a single voltage level within the substation including transformation from that voltage level), including any generation capacity connected thereto.
   D. The delayed clearing of a three-phase fault at any system location due to the failure of a first-protective-zone circuit breaker to open to clear the fault.

FCG Planning Criteria

A. More Probable Contingencies - to be sustained without load loss other than that connected to the lost element.

1. Loss of generation - sudden loss of any one generator

2. Loss of transmission

   a. single line outage of any one transmission line.

   b. loss of any one transformer bank at any one generating plant or bulk transmission substation.

B. Less Probable Contingencies - to be sustained with possible loss of some load.

1. Loss of generation - sudden loss of any on generator while any one generator is out of service.

2. Loss of transmission - loss of any two double-circuit tower transmission lines.

3. Loss of generation and transmission - loss of any one transmission line during the scheduled-outage of any one generator.

These regional criteria serve as minimums for all SERC systems and discussion with FP&L staff indicated they were at least consonant with the FCG Criteria which is followed by FP&L. Because of the limited interconnection capability between Florida Subregion electric systems and electric systems in the remainder of SERC which are interconnected with all other electric systems east of the line formed by the eastern borders of Montana, Wyoming, Colorado and New Mexico excluding Texas, presently major losses of Peninsula Florida generation (largest plant - Turkey Point (FPL), 2066 MW or largest unit - Crystal River No. 3 (FLPC), 824 MW) would result in the separate of the Florida systems from the remainder of the Eastern Interconnection. This assumes that the specified plant and units were operating at their rated capabilities and there were no scheduled transfers to Florida.

In 1983, the present scheduled operational date for the St. Lucie No. 2, 802 MW nuclear unit, the largest Florida Sub-region plant and unit respectively will be the FLPC's 2,280 MW Crystal River plant and its Crystal River No. 3, 824 MW, nuclear unit. However, for transient stability study purposes, the largest Florida peninsula plants in 1983 would be Turkey Point (2,066 MW), St. Lucie (1,579 MW), Martin (1,550 MW) Manatee (1,528 MW), and Crystal River 500 kV-Nos.3 & 4 (1,464 MW). By then, the Installed Interconnection Capability (IIC) and the Emergency Transfer Capability (ETC) between Florida and Georgia will increase as follows:

	Florida to Southern		Southern to Florida	
	1979	1983	1979	1983
	MW	MW	MW	MW
IIC	200	900	300	1000
ETC	50	550	100	600

The interconnections between Peninsula Florida and the remainder of the Eastern Interconnection will be:

Yulee (FP&L) - Kingsland (GOPC)	230 kV
Suwanee (FPC) - Pinegrove (GOPC)	230 kV
Port St. Joe (FPC) - Callaway (GUPC)	230 kV
Suwanee Plant (FPC) - Twin Lakes (GUPC)	115 kV
Jasper (FPC) - Pinegrove (GOPC)	115 kV
Jasper (FPC) - Traver (GOPC)	115 kV
1/ Jennings (FPC) - Valdosta (GOPC)	69 kV
Monicello (FPC) - Boston (GOPC)	69 kV
1/ City of Quincy (FPC) - Attapulgus (GOPC)	69 kV

1/ Normally Open Interconnections

Restricting discussion to the Southern to Florida subregion capabilities, the IIC and ETC values respectively increase by 700 MW/333.33% and 500 MW/600%. These increased values result from transmission reinforcements between the Florida and Southern Subregions: (1) 1980 operation of the Yulee (FPL) - Kingsland (Georgia Power Corp. - GUPC) 10 mile 230 kV line, and (2) 1982 uprate to 230 kV and retermination to Calloway (GUPC) of the Port St. Joe (FLPC) - Wewa 37.75 mile 115 kV line and other Florida Subregion transmission reinforcements. Between December 31, 1978 and December 31, 1983, 748.56 miles of 230 kV operated transmission line will be added to the Florida Subregion either as new line additions or uprating of existing 115 kV lines. In addition, 125.4 miles of 500 kV transmission, all on the FP&L system, will be added. Of the planned Florida 230 kV line additions, 342.40 miles/45.7% additions are on the FP&L system. The FP&L 500 kV additions through 1983 plus 199 miles planned for addition during the 1984-1988 period will establish 500 kV as the FP&L primary transmission level in their North Central, Eastern, Southeast and Miami Divisions. In 1978, these Divisions constituted 76% (33,379.9 GWH) of system energy supplied and 78% (6540 MW) of the systems non coincident peak demand.

While appropriate transient stability and load flow studies for the 1983 and subsequent periods must be performed to satisfy from an engineering viewpoint compliance with planning criteria, it is reasonable to presume that with the planned Florida - Georgia transmission interface reinforcements along with those in Florida, for the loss of the Crystal River No. 3, 824 MW, nuclear unit, the Florida systems should remain interconnected with the Eastern Interconnection. In 1983, for the loss of the Crystal River No. 3 unit, about 778.1 MW (96%) of the instantaneous electrical energy balance adjustment will come from outside the Florida system through the Florida - Georgia interface and in terms of the planned 1983 interface capability of 1000 MW (IIC), the Florida systems should remain interconnected with the Eastern Interconnection as long as: (1) no major interface lines are out of service; (2) no major transmission paths from the Florida - Georgia interface south are unavailable; and (3) the scheduled Georgia to Florida transfer is less than about 400 MW. The loss of this unit might occur as a result of at least one of two events: (1) by tripping of the unit or (2) loss of both 500 kV lines from the plant (outage of one 500 kV line due to fault during the maintainance outage of the other 500 kV line), however, this would also cause the loss of the Crystal River No. 4, 640 MW, coal fired unit, planned for installation in 1982, as well resulting in a total loss of 1,464 MW. This would exceed in generation loss magnitude as would the loss of St. Lucie Nos. 1 and 2, 1,579 MW, the largest situation provided in the August 31, 1979 FP&L analysis. Therefrom, I would presume that from a transient stability viewpoint, that initiation of Peninsula Florida separation from the Eastern Interconnection would begin in less than 3.87 seconds and the automatic underfrequency relaying will operate to shed firm load.

The preceeding discussion does not indicate the design adequacy, with respect to SERC Regional Criteria for loss of generation, load or transmission. This can only be determined through transient stability studies. My discussion with both FP&L and FCG staff concluded that FCG studies for 1980-85 period had not been done but were scheduled for later this year. However, the transient stability evaluation by FP&L confirms in part that no separation would occur or firm load shedding with an import of 300 MW and the loss of 800 MW.

Spinning reserve criteria for the Peninsula Florida systems is described by the FCG Operating Committee in the FCG Operating Handbook which is used in conjunction with the North Anmerican Power Systems Interconnection Committee (NAPSIC) Operating Manual. While I have not seen the FCG Operating Handbook, the SERC Coordinated Bulk Power Supply Program of April 11, 1979 under item 7-A, "Coordination of Operations", for the Florida Subregion summarizes several of the coordinated practices including the Operating Reserve Policy. Daily Operating Reserve is that amount of generating capability and/or equivalent load relief over and above fore-casted daily peak load which is available to respond to load connected and responsive immediately to load changes and capable of becoming fully loaded in response to a frequency decline of 0.5 Hz (to 59.5 Hz from nominal or scheduled frequency of 60 Hz); and, (2) Supplemental Reserve - any generating capability and/or load relief measure which can be made fully responsive to its planned for reserve capability within 30 minutes.

The Daily Operating Reserve maintained by the combined systems (Florida Subregion systems) is equal to, or greater than, the sum of the Peak Capabiltiy Ratings of the two largest units in service. Spinning Reserve is maintained at, or greater than, the Peak Capability Rating of the largest generating unit in service. The balance of the Daily Operating Reserve is Supplemental Reserve and upon the loss of a unit, Supplemental Reserve is converted to Spinning Reserve, if required, to restore the recommended level of Spinning Reserve.

Daily Operating Reserve and Spinning Reserve requirements are allocated among participants, weighted 50% in proportion to each partcipant's maximum demand for the preceeding-year and 50% for the Peak Capability of his largest unit. The effect on a participant's spinning reserve allocation must be fully considered before agreeing to sell power to another participant; the protection of a new unit undergoing shakedown is the owner's responsibiltiy; based upon 5% governors, no more than 16.6% of the Continuous Capability of a unit can be assigned to any one unit; and, each participant's Daily Operating Reserve allocation should be available to other participants without restriction by transformer, line or other limitations.

In the event that Spinning Reserve and Eastern Interconnection transmission support is insufficient, the Peninsula Florida system has a Load Preservation Program encorporating automatic underfrequency relaying (UFR). Through UFR operation a minimum of 2,859 MW (16.6%), 2,829 MW (16.4%) and 4,438 MW (25.7%) of load will automatically be shed respectively by a frequency decline to 59.0 Hz, 58.7 Hz and 58.5 Hz. This represents 58.7% of the 1979 summer peak load and would leave at least 41.3% (7,124.4 MW) of load and generation operable for restoration of lost generation and/or load. In addition, each Florida Subregion system has generating units capable of operating for extended periods isolated from the system and carrying their own auxiliary power loads, which should reduce system restoration time.

Largest Peninsula Florida Generating Unit and Plant, 1978 - 1985 1/

	1978	1979 - 1981
Largest Plant	2/ FP&L Turkey Point 2066 MW	FP&L Turkey Point 3/ 2066 MW
Largest Unit	2/ FLPC Crystal River No. 3 797 MW	FLPC Crystal River No. 3 824 MW

	1982 - 1983	1984 - 1985
Largest Plant	FLPC Crystal River 4/ 2280 MW	FLPC Crystal River 5/ 2920 MW
Largest Unit	FLPC Crystal River No. 3 824 MW	FLPC Crystal River No. 3 824MW

1/ April 1, 1979, Southeastern Electric Reliability Council (SERC), Coordinated Bulk Power Supply Program for the 1979 - 1998 period.

2/ FP&L - Florida Power & Light Company;
FLPC - Florida Power Corporation.

3/ Unit Nos. 1 & 2 (367 MW @) connected to N.E. and N.W. 230 kV busses; Unit Nos. 3 & 4 (666 MW @) connected to S. E. and S. W. 230 kV busses; bus tie breakers between both North and South bus sections.

4/ Unit Nos. 1 & 2 (383 MW, 433 MW) on 230 kV; Unit Nos. 3 & 4 (824 MW, 640 MW) on 500 kV; No kV to 230 kV connection at plant substation.

5/ Unit Nos. 1, 2 & 5 (383 MW, 640 MW) on 230 kV; Unit Nos. 3 & 4 on 500 kV; No 500 kV to 230 kV connection at plant substation.

Florida Power & Light Company
Interconnection with Other
Peninsula Florida Systems

The Florida Power & Light Company (FP&L) has a total installed generating capacity of 10,491 MW and additions through 1983 (Martin Nos. 1 & 2, 775 MW @, 1980 and 1981; Dade Solid Waste Facility, 40 MW, 1980; and, St. Lucie No. 2, 802 MW, 1983) of 2,392 MW will raise the total system capacity to 13,333 MW. The Florida Subregion generation and load (summer peak) are projected to grow by 1983 respectively from 21,800 MW and 17,261 MW to 26,782 MW and 21,528 MW. Between FP&L and other Peninsula Florida systems there are sixteen interconnections (Table I) operating at 69 kV to 230 kV. Presently, three of these inter - connections are for limited area backup protection and are normally open. Therefore, there are 7-230 kV, 2-138 kV, 1-115 kV, and 3-69 kV normally closed interconnections with Peninsula Florida generating utilities. By the spring of 1980, the Yulee to Kingsland (Georgia Power Company) 230 kV line will be operational, providing one more source of emergency supply to FP&L directly and other Peninsula Florida system.

As part of the ongoing assessment of the adequacy of the Peninsula Florida system, the January 1979 Florida Electric Power Coordinating Group (FCG)/System Planning Committee/Transmission Task Force's Transmission Load flow Analysis Report, 1982 & 1987 Summer Periods evaluated among other through the single-line-outage adequacy of the 1982 Peninsula Florida transmission system

Interconnections Between Florida Power & Light Company and Ohter Peninsula Florida Systems - 1979 Generation

Florida Power Corporation - 3,647 MW	
1. Sanford Plant - North Longwood	230 kV
2. Brevard - Holopaw - Canoe Creek - West Lake Wales	230 kV
(from Brevard, there are two 230 kV lines via Malabar to Midway substation)	
3. Sanford Plant - Turner	230 kV
4. Normally open	
a. Columbia - Live Oak Tap - East Oak	69 kV
b. Taps off of Palatka Plant Deland 115 kV line	
(1) Barberville	115/69 kV
(2) Deland East	115 kV
Jacksonville Electric Authority - 1884 MW	
1. Baldwin - Normandy	115 kV
2. Baldwin 115/230 kV - Duval - Normandy	230 kV
3. Putnam Plant - Orangedale Greenland (JEA) - Robinwood Acreas	230 kV
Tampa Electric Company - 2,505 MW	
1. Ringling - Manatee Plant - Ruskin	230/69 kV
2. Ringling - Gillette - Ruskin	230 kV
Orlando Utilities Commission - 742 MW	
1. Cape Canaveral Plant - Indian River	230 kV
Lake Worth Utilities Authority - 141 MW	
1. Hypoluxo - Plant Sub	138 kV
(from Hypoluxo, there is a 138 kV line to Ranch 138/230 kV)	

City of Vero Beach - 133 MW

1. West (138 kV) - South Sub.	69 kV

Fort Pierce Utilities Authority - 116 MW

1. Hartman (138 kV) - Sub. No. 1 (from Hartman, there is a 138 kV line to Midway 138/230 kV and a 138 kV line via West to Molabar 138/230 kV	138/69 kV

City of Honestead - 52 MW

1. Lucy - McGinn Sub.	138 kV

and the Area-Transfer-Capability (import capability) of the major systems. That study concluded the following:

Single-Line-Outages

The Peninsula Florida 1982 system performed adequately and within design limits for all but three contingencies which produced up to 5% overloads on three facilities:

a) L/O (FP&L) Sanford-North Longwood 230 kV

(FLPC) Turner - Lake Emma 115 kV loaded to 103% of rating and low voltages experienced in FLPC's eastern division.

b) L/O (FP&L) Ringling - Laurelwood 230 kV

(FP&L) Ringling - Charlotter 230 kV loaded to 104% of rating.

c) L/O Woodmore (FLPC) - Pine Hills (ORLA) 230 kV)

(ORLA) Southwood - Turkey Lake 115 kV line loads to 105% of its emeergency rating.

It should be noted that none of these overloads exceeds 5% and therefore are not considered major overloads. Furthermore, they would only occur if peak load conditions existed coincident with the specific line outage and even so, adjustments could be made in generation schedules to alleviate the overload condition.

FP&L's Import Case

The Big Bend to Gillette 230 kV line loaded to 442 MVA, 10% of its rating when 1,100 MW was imported by FP&L. The import to FP&L was simulated such that Florida Power Corporation, Tampa Electric Company, and Jacksonville Electric Authority each exported one-third (367 MW) of the power.

The Big Bend - Gillette 230 kV line includes an intertie with the Tampa Electric Company (TEC) at the Ruskin substation, one of two TEC interconnection points with FP&L, so that the about 40 MVA overload probably could be reduced by reducing the TEC's share of the import by about 40-50 MW.

The FP&L 1,100 MW import level (11.1% of FP&L's 1982 peak load represented) ~~would~~ cover most combinations of two unit outages on the FP&L system except the unavailability of St. Lucie Nos. 1 & 2 (1,589 MW), Manatee Nos. 1 & 2 (1,528 MW), Turkey Point Nos. 3 & 4 (1,332 MW) Maratin Nos. 1 & 2 (1,550 MW) and some combinations of these. However, it is unlikely that a 1,100 MW import requirement would occur because of the maintenance outage of one unit plus the forced outage of another unit during peak load periods.