BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040001-EI

In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE INCENTIVE
FACTOR.

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VOLUME 7

Pages 776 through 952

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER CHARLES M. DAVIDSON
DATE:	Tuesday, November 9, 2004
TIME:	Commenced at 9:30 a.m. Concluded at 5:32 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

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P R O C E E D I N G S

THE WITNESS: (Transcript follows in sequence from Volume 6.)

CHAIRMAN BAEZ: Go back on the record. Who is going to introduce Mr. Dismukes?

MR. MOYLE: I am, Mr. Chairman.

Whereupon,

DAVID E. DISMUKES

was called as a witness on behalf of Mr. Churbuck and FIPUG, and testified as follows:

DIRECT EXAMINATION

BY MR. MOYLE:

Q Sir, will you please affirm for the Commission that you previously have been sworn as a witness.

A Yes, I have been sworn.

Q Please state your name and address for the record?

A My name is David E. Dismukes. My address is 6455 Overton Street, Baton Rouge, Louisiana 70808.

Q And by whom are you employed?

A The Arcadian Consulting Group.

Q Did you cause to be filed in this proceeding direct testimony that is submitted on behalf of Mr. Churbuck and FIPUG?

A Yes, sir, I did.

Q And did you also have an errata sheet prepared that

reflects changes to your testimony?

A Yes, sir, I did.

MR. MOYLE: And I have handed out a copy of that errata sheet. I guess I can have it marked, Mr. Chairman.

CHAIRMAN BAEZ: Okay. We will mark it Exhibit 70, and that will be errata sheet to the testimony of David Dismukes.

(Exhibit 70 marked for identification.)

BY MR. MOYLE:

Q Do you have any other changes to your direct prefiled testimony, Mr. Dismukes?

A Yes, sir. There was one other little change on Exhibit DED-2 that I found after preparing the errata sheet.

Q I'm sorry, what exhibit?

A DED-2.

Q And what is that change?

A The first plant that is listed, Number 6, Mobile Energy Services ought to be Tenaska Central Alabama, it should be Number 8 instead of Number 6. That changes the capacity from 125 megawatts to 808, and it changes the total of the operating facilities to 3,283 megawatts.

Q All right. With those changes, both the ones you just identified and the changes contained in your errata sheet, if I asked you the questions set forth in your direct prefiled testimony today and you provided answers, would your answers be

the same?

A Yes, sir, they would.

MR. MOYLE: Mr. Chairman, I would ask that the prefiled testimony be inserted into the record as if read.

CHAIRMAN BAEZ: Without objection, show the direct testimony of David Dismukes entered into the record as though read, and note for the record that there is an errata sheet corresponding to it marked as Exhibit 70.

BY MR. MOYLE:

Q And, Mr. Dismukes, did you have exhibits that were filed along with your prefiled testimony, Exhibits DED-1 to 10?

A Yes, sir, I did.

MR. MOYLE: Mr. Chairman, I would ask that those be marked and identified at this time.

CHAIRMAN BAEZ: I believe they are part of Exhibit 1 actually, and they have been premarked as Exhibits 49 through 58.

MR. MOYLE: And they are already in the record, is that correct?

CHAIRMAN BAEZ: They are not in the record, they have been marked. So at the end of Mr. Dismukes' testimony and redirect we will move them in.

I. INTRODUCTION

Q WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A My name is David E. Dismukes. My business address is 6455 Overton Street, Baton Rouge, Louisiana.

Q WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ELECTRIC AND REGULATED INDUSTRIES?

A Yes. Attachment 1 to my testimony provides my academic vitae that includes a full listing of my publications, presentations, and pre-filed expert witness testimony, expert reports, and affidavits.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony is being sponsored by Power Systems Manufacturing, LLC ("PSM") and Thomas K. Churbuck to evaluate the reasonableness of Florida Power and Light Company's ("FPL" or "the Company") proposal to recover the costs associated with three purchased power agreements ("PPA") with Southern

Company Services, Inc. ("SCSI"), a corporate affiliate of the Southern Company. ("Southern"). Additionally, the Florida Industrial Power Users Group ("FIPUG") has agreed to sponsor my testimony because it is consistent with the group's stated policy of supporting wholesale competition for electric supply.

Q HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Summary of FPL's PPA Request
- Section IV: FPL's PPA Proposal Circumvents the Commission's Competitive Bidding Process
- Section V: The Current Fuel Proceeding is an Inappropriate Proceeding for Evaluating the Company's PPA Proposals
- Section VI: The Additional Benefits Claimed by the Company Appear to be Limited and Do Not Overwhelm the Potential Upsides of a Competitive Bidding Process
- Section VII: The Company's Review of the Market Does Not Appear to be Complete and Includes a Number of Errors
- Section VII: Summary and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A I recommend that the Commission separate the cost recovery issue for three purchased power contracts with subsidiaries of Southern from the remaining issues in this fuel proceeding for the following reasons:

(1) The proposed purchased power contracts represent a considerable commitment for FPL that extends well into the future. The proposal raises numerous complex issues that should not be considered on a relatively expedited basis.

(2) Because of the magnitude of this request, the terms, conditions, and rates for these proposed contracts should be compared to the best alternative available in the market. The Company has not conducted a Request for Proposal ("RFP") process as envisioned in the FPSC Rule 25-22.082; therefore, the Commission cannot be assured that this resource proposal is the most cost effect in the market for ratepayers. In fact, the Company has admitted that its self-build option is some $60 to $80 million lower than the PPA contracts FPL is asking the Commission to approve in this proceeding. [Hartman Direct Testimony, 15: 17-18.]

(3) The extent to which the Company has queried the market is questionable. Further, a number of the "additional benefits" associated with these contracts are questionable. If the Commission wishes to have the Company seek these types of additional benefits, they should be written into the requirements of a competitive RFP or similar solicitation submitted to the market.

(4) Separating this issue would not appear to harm ratepayers since the Company has noted that its current contract terms with Southern allow 6 months for regulatory approval or until

transmission rights are obtained, whichever is later. [Hartman Direct Testimony, 6:17-18. Section 7.4.1 of the PPA contains a transmission deadline date which has been redacted.]

(5) Separating this issue from the remaining issues in this docket, and considering it in a more thorough fashion by testing the new contracts against the competitive market through an RFP process, would serve the public interest by ensuring "that a public utility's selection of a proposed generation addition [inside or outside of Florida] is the most cost-effective alternative available." [F.A.C., FPSC Rule 25-22.082]

Q DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A Yes. If the Commission rejects my primary recommendation to separate the issues associated with the Company's proposed PPA from this proceeding, then I would recommend that the Commission not approve the Company's proposed PPAs at this time. I base this alternative recommendation on the following points:

(1) The Company has not conducted a thorough competitive bidding or other procurement process for these resources;

(2) The Company has not provided complete and detailed information in its filing proving that these PPAs are the least cost option available to ratepayers.

(3) The Company has indicated that its self-build option is a lower-cost resource than the proposed PPAs. The purported additional

benefits associated with the Company's proposed PPAs do not offset these potential costs savings for ratepayers. The Company should be required to compare this self-build option to all potential contracts and resource alternatives in the market through a competitive bidding process.

III. SUMMARY OF FPL'S PPA REQUEST

Q WOULD YOU PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S FUEL FILING?

A The Company has requested that the Commission approve its proposed levelized fuel recovery charge for the period January 2005 through December 2005. In addition to setting the fuel recovery charge, the Company has requested approval for recovery of three purchased power contracts with SCSI, a subsidiary of Southern through the fuel and purchased power cost recovery clause and the capacity recovery clause.

Q PLEASE DESCRIBE THE THREE PURCHASED POWER CONTRACTS THAT THE COMPANY HAS REQUESTED TO BE INCLUDED AND APPROVED IN THIS DOCKET.

A The contracts consist of:

- 165 megawatts ("MW") of firm capacity and energy from a coal generation unit in Georgia;
- Up to 600 MW of energy and capacity from a combined cycle facility in Alabama; and

- 190 MW of energy and capacity from an additional combined cycle facility in Alabama.

The total contract amount for the three purchases is 955 MW. After allowances for transmission losses that occur on the Southern system (not considering the additional transmission losses on the FPL system), the net injection into the Company's system would be 930 MW. All three contracts begin on June 1, 2010 and end on December 31, 2015. The contracts tied to natural gas units include options for additional two-year extensions that can be exercised presumably at any time prior to January 2010. The contribution each of these contracts makes to the total purchase amount is provided in Exhibit DED-1. The proposed PPAs represent new contracts that follow up on an existing agreement referred to as the Unit Power Sales Agreement (the "UPS Agreement"). However most of the units to which these new contracts are tied, differ from the original UPS Agreement. The original agreement expires on May 31, 2010, roughly six years from the current date.

IV. FPL'S PPA PROPOSAL CIRCUMVENTS THE COMMISSION'S COMPETITIVE BIDDING RULE

Q WHY DOES THE COMPANY'S PPA PROPOSAL CIRCUMVENT THE COMMISSION'S COMPETITIVE BIDDING RULES?

A These new contracts circumvent if not the Commission's bidding rule itself, then at least the spirit of the rule. The PPA has not been subjected to a competitive bidding process, and has only been "tested" to the market in an incomplete and cursory manner. Section 25-22.082 of the Commission's Rules

outlines a process that utilities are required to follow in evaluating the need and selection of additional generating capacity. This rule requires utilities to compare proposed resource acquisitions to a RFP process. The competitive bidding provisions of this rule were established to ensure that the most cost effective resources are secured for ratepayers. By testing the competitive market, the Commission can be assured that the least cost resource has been secured for ratepayers.

Q DOES THE COMPETITIVE BIDDING RULE RELATE ONLY TO THE CONSTRUCTION OF NEW GENERATING FACILITIES?

A Strictly speaking, yes. The Scope and Intent section of the Rule notes that the purpose of the competitive bidding requirement is to provide the Commission with information in evaluating utility proposals under F.S. Section 403.519, also known as the Power Plant Siting Act. This statute outlines the terms and conditions under which utilities are allowed to construct new power plants in the state. The Company's proposed PPA is not associated with the construction of a new facility. However, the size and magnitude of the capacity represented by these contracts, nearly 1,000 MW, is comparable to a large generating facility. In order to assess the justness and reasonableness of these proposed new contracts, the Commission should subject them to a competitive bidding process.

Q SHOULD THE COMMISSION BE PRECLUDED FROM REQUIRING COMPETITIVE BIDDING IN INSTANCES OF THIS NATURE?

dampened in the future. Second, while some of these benefits may actually be positive, none appear to be overwhelming enough to offset the $60 to $80 million in ratepayer benefits that are quantifiable in today's dollars. Third, a large number of the benefits outlined by the Company, like firm gas transportation on a non-Florida gas transmission line, could be written into a solicitation presented to the market.. Fourth, and most importantly, all of these purported benefits could ultimately be secured if Southern were to bid them into a RFP process and win the resulting bid. This outcome would be a "win-win" for the Commission if FPL proved that this Southern proposal, after a comparison to all market alternatives, was the lowest cost alternative. In such an instance, the "benefits" outlined by the Company would be secured, and the Commission could ensure that the least-cost resource was selected for ratepayers.

Q BY ACKNOWLEDGING THESE SAVINGS AREN'T YOU SUPPORTING THE COMPANY'S SELF-BUILD OPTION?

A No. The self-build option sets the lower threshold of potential ratepayer savings that could be obtained if this PPA were compared to the market. The Commission has nothing to lose by requiring FPL to submit this resource need to the market or by refusing to approve the PPA at this time, signaling to FPL the Commission believes it prudent to actively and thoroughly test market before rushing to seek approval of these contracts. At a minimum, by FPL's own estimates, ratepayer savings could range from $60 to $80 million, or more if a lower cost competitive offer is submitted and wins the award.

V. THE CURRENT FUEL PROCEEDING IS AN INAPRROPRIATE PROCEEDING FOR EVALUATING THE COMPANY'S PPA PROPOSALS

Q DO YOU BELIEVE THAT THE CURRENT FUEL PROCEEDING IS THE MOST APPROPRIATE PLACE TO CONSIDER THE COMPANY'S PPA REQUEST?

A No. These contracts should not be addressed in this proceeding for a number of reasons. First, the proposed PPAs have nothing to do with the proposed 2005 fuel adjustments currently being reviewed by the Commission. Second, these PPAs are more appropriately addressed under the context of a proceeding directed by the requirements of the Commission's Capacity Addition Rule. Third, the PPAs involve a significant commitment of resources and present a host of issues that are better evaluated in a proceeding that is not being rushed to conclusion.

Q WOULD YOU PLEASE ELABORATE ON YOUR FIRST POINT?

A Yes. The purpose of the current fuel proceeding is threefold. The first is to true up prior year(s) projected to actual fuel costs to account for any over/under collections in the fuel adjustment clause. The second is to determine the reasonableness of fuel rates presently being charged by the Company for the current year. The third is to review and determine the reasonableness of fuel rates that will be charged by the Company over the next year. The PPAs proposed by the Company will not be initiated for six years (2010) and their renegotiation has little to do with 2005 fuel costs or purchased power. The

Commission would have plenty of time to review this proposal outside of the context of determining the upcoming years' fuel costs.

Q AS A PRACTICAL MATTER, DO YOU THINK THE INCLUSION OF THE PPA ISSUE IN THE CURRENT PROCEEDING UNNCESSARILY EXPEDITES THE REVIEW PROCESS FOR THE PROPOSALS?

A Yes. The Company's request for these new PPAs was provided in its pre-filed testimony on September 9, 2004. Interveners have been required to review the reasonableness of this request, issue and analyze discovery, and file opposing testimony by October 4, 2004 – a period slightly over 3 weeks. The FPSC Staff will only have an additional week to review the Company's proposal, as well as other intervener's positions. It is my opinion that this review period is exceptionally quick for a capacity addition of this magnitude.

Q DO THE TIMELINES AND NOTIFICATION PERIODS UNDER THE COMMISSION'S CAPACITY ADDITION RULES PROVIDE MORE TIME FOR EVALUATION THAN THE CURRENT PROCEEDING?

A Yes. The Commission's Rules provide several opportunities for advance notification and analysis when a utility has a resource acquisition need. For instance, the Commission's Rules first require a utility to announce and publish its resource requirement need and its Request for Proposals ("RFP") in various publications. The Company must then provide at least 60 days for responses to the RFP as well as any additional time if changes are made to the RFP, or the Company alters its own estimates of its self-build option. Next, the Company must review and determine if its self-build option is more cost effective than any

proposals received. The process is reasonable and appears to be developed in a manner that balances the need for a thoughtful analysis with a conscientious decision. The process can feasibly be completed within a six month period – a period much longer than the one month interveners have had in this proceeding.

Q IS IMMEDIATE APPROVAL OF THE PROPOSED CONTRACTS IMPERATIVE?

A No. The Company claims that the current provisions of its contracts allow for the longer of six months to obtain regulatory approval as well as any time needed to obtain firm transmission rights. [Hartman Direct Testimony, 18:6.] Additionally, if the Company were to issue a RFP for capacity, Southern would be eligible to bid the current contracts against other bidders. Thus, there is minimal impact on either company with the issuance of an RFP, and only potential gains to ratepayers should any better offers surface. If an RFP process were conducted, the Commission could be satisfied that the purchased power contracts are the best alternative available.

Q DOES THE EXPIRATION OF THE EXISTING UPS AGREEMENT WITH SOUTHERN REPRESENT THE MOST IMMEDIATE RESOURCE ISSUE THE COMPANY NEEDS TO ADDRESS WITHIN THE CONTEXT OF ITS LAST TEN YEAR SITE PLAN?

A No, while the Company has noted that contract negotiations are an issue throughout the 2004-2013 resource acquisition process, the two more immediate resource requirements include the projected construction of two new combustion turbine units at the Midway site in 2008, or an alternative resource(s) as obtained

through an RFP; and the projected construction of a new combined cycle unit at the Corbett site in 2009, or an alternative resource(s) as obtained through an RFP ["Ten Year Power Plant Site Plan, Florida Power & Light, submitted to Florida Public Service Commission, April 2004]. It would appear that in the order of addressing resource needs, these two potential projects would be more pressing than the proposed PPAs under consideration in this proceeding.

Q THERE HAS BEEN AN ONGOING PROCEEDING AT THE FERC RELATED TO MARKET POWER ISSUES AS THEY RELATE TO SOUTHERN COMPANY. HOW DOES THIS IMPACT THE TIMING OF THE COMMISSION'S CONSIDERATION OF THIS PROPOSAL?

A There has been an ongoing analysis of market power issues in the southeast for several years. The FERC initiated a review of rates when Southern Company, Entergy, and AEP all submitted applications in support of their triennial market-based rate authority. Subsequently in 2001, the FERC decided to change the manner in which it evaluated market power issues away from the more traditional "hub-and-spoke" analysis to one that is called a "standard market assessment" ("SMA"). Under the standards of the new test, Southern, as well as the other two utilities that were part of the proceeding, were found to fail their market power screen, indicating that further analysis of market power was required.

Q WERE THESE UTILITIES, INCLUDING SOUTHERN, DENIED MARKET BASED RATE AUTHORITY?

A No. While each of the utilities failed the new SMA test, the FERC received several motions for rehearing on the soundness of the SMA standard. It acted on these motions by soliciting several rounds of comments, holding a technical conference, and soliciting feedback on a FERC Staff paper. The process concluded on April 14, 2004 and resulted in two new indicative tests being adopted to screen for market power.

Q DID THE FERC ALLOW A REHEARING ON THIS ORDER?

A No, the FERC denied a rehearing on the April 14, 2004 Order, but offered clarifications in its Order on Rehearing issued July 8, 2004.

Q DID FERC ISSSUE A RECENT ORDER REQUIRING SOUTHERN TO MAKE A MARKET POWER FILING BASED UPON ITS NEW TESTS?

A Yes. On July 8, 2004 the FERC issued an Order on Rehearing that requires a pair of tests to be passed to screen for indications of market power prior to an applicant's receiving market based rate approval. The first test, a "Pivotal Supplier Test," is an analysis based on a control area's peak demand and the second is a "Market Share Test." Failing either test leads to the presumption of market power, but the applicant is allowed to rebut the presumption with additional data.

Q WHAT ELSE DID THE ORDER REQUIRE?

A The order required Southern Company Energy Marketing, LP, among other utilities, to file generation power market analyses within 30 days of the Order on Rehearing.

Q HAS SOUTHERN FILED THE REQUIRED INFORMATION?

A Yes, Southern submitted a compliance filing on August 9, 2004 to the FERC in Docket No. ER97-4166-015 and has noted that it "...fails the Commission's wholesale market share screen in the Southern control area." [Southern Company Compliance Filing, SC-20: ¶19.]

Q HOW DOES THIS IMPACT THE TIMING ISSUES ASSOCIATED WITH FPL'S PROPOSED PPAS WITH SOUTHERN?

A The recent decision, and filing by Southern, creates uncertainty associated with FPL's proposed PPA. One question that the Commission should consider is that if Southern is found by the FERC to have market power, and the FERC removes Southern's market-based rate authority, what will happen to any contracts like the one proposed by FPL? Will these contracts be grandfathered to their contracted terms, or will Southern be required to provide FPL (and Florida ratepayers) cost-based rates? I believe this is an important issue, and justifies spinning this issue into a separate proceeding, and taking a "go-slow" approach.

VI. THE ADDITIONAL BENEFITS CLAIMED BY THE COMPANY APPEAR TO BE LIMITED AND DO NOT OVERWHELM THE POTENTIAL UPSIDE OF A COMPETITIVE BIDDING PROCESS

Q WOULD YOU PLEASE EXPLAIN THE ADDITIONAL BENEFITS THE COMPANY CLAIMS SUPPORT APPROVAL OF ITS PPA REQUEST?

A The Company has noted that the proposed PPAs offer a number of additional benefits that include:

(1) Fuel diversity by including some 165 MW of coal generation;

(2) Optionality by allowing the Company first rights of refusal on any future coal capacity presumably offered to the market from two of Southern's coal units;

(3) Retention of 930 MW of firm power transmission rights;

(4) Firm gas transportation rights on a pipeline independent of the two currently serving Florida;

(5) Increased reliability by having the ability to secure capacity and/or purchased energy from outside Florida; and

(6) The ability to defer making a long term commitment on a self-build or longer term PPA. [Hartman Direct Testimony, 9:7-22; 10:1-4.]

Q DO YOU AGREE THAT THESE BENEFITS ARE IMPORTANT ENOUGH FOR THE COMMISSION TO ALLOW THE COMPANY TO AVOID CONDUCTING AN RFP PROCESS?

A No. While several of these benefits appear important on the surface, many are questionable in nature, and even if they were to materialize, are not significant enough to justify the Commission giving the Company a pass on conducting an RFP process for a 930 MW capacity acquisition. Further, most all of the benefits outlined by the Company could be included as requirements in a future RFP solicitation. In such an instance, these additional benefits could be secured, along with the knowledge that the new contracts were the most economical in the market.

Q TWO OF THE BENEFITS LISTED BY THE COMPANY ARE RELATED TO SECURING SOLID FUEL-BASED RESOURCES. DO YOU AGREE THAT THESE ARE IMPORTANT BENEFITS?

A Not entirely. While there are some solid fuel benefits associated with this contract, only 165 MW of the entire proposed PPA agreement is associated with coal generation. This represents only 17 percent of the total agreement, and less than one percent (0.7 percent) of the Company's overall generation mix. The overwhelming bulk of this proposed contract is associated with natural gas-fired resources (83 percent). While a portion of this agreement is solid fuel-based, it is such a small percentage, and does not make a meaningful impact on the Company's overall generating fuel mix. Further, if the Company is interested in securing solid fuel, or solid fuel-type resources, it should indicate such in a solicitation to the market.

Q WHAT ABOUT THE FIRST RIGHT OF REFUSAL THE COMPANY WILL GET ON THE TWO SOUTHERN COAL UNITS?

A These potential options are problematic for two reasons. First, it is not clear when, where, and to what extent Southern Company would ever make any capacity and/or energy available from these units. The Company's filing is not clear in this regard so it is virtually impossible to determine whether this is a meaningful opportunity. Second, even if Southern were to offer a substantial portion of these units to the market, and even if FPL were interested in acquiring this capacity, such procurement should also be subjected to market forces.. This is an option that the Company should not be allowed to exercise without

ensuring that other more competitive opportunities (including other solid fuel options) are not available in the market.

Q WHAT ABOUT THE BENEFITS ASSOCIATED WITH RETAINING 930 MW OF FIRM POWER TRANSMISSION CAPACITY FROM SERC?

A The ability to secure 930 MW of transmission rights from SERC into Florida may have some benefits, but the conditions under which these benefits could be realized are not clearly explained in the Company's proposal. One potentially bothersome issue is the nature to which these transmission rights are tied exclusively to obtaining power from Southern Company, as opposed to being used by any other competitive energy providers in the SERC region that may want to serve FPL. The Company has noted the conditions precedent in the contracts are linked throughout all three potential agreements. The Company states that "...although separate in form and relating to different generating units, [these three contracts] in fact constitute a single, composite power purchase option for purposes of the Commission's review and approval." [Hartman Direct Testimony, 6:22; 7:1.] Thus, it appears that the Company's position is that if it wants to maintain these transmission benefits, they have to sign this deal with Southern.

Q UNDER WHAT TERMS AND CONDITIONS WILL THE COMPANY BE ABLE TO ROLL-OVER ITS TRANSMISSION RIGHTS WITH SOUTHERN?

A According to the Company, it will be able to roll-over its grandfathered transmission rights if it can show that the changed delivery points from the existing agreement do not cause substantial changes in the transmission

provider's flows. [Hartman Direct Testimony, 8: 2-5.] The Company indicates that given the relative similarity in the flows, it "should" be able to secure these rights. [Hartman Direct Testimony, 8: 12-15.] However, the Company offers little in the way of evidence to support its contention that it "should" be able to secure these rights.

Q HAVE ROLLOVER RIGHTS BEEN USED BY A WHOLESALE CUSTOMER TO TAKE SERVICE FROM A COMPETITIVE MERCHANT PROVIDER?

A Yes. There have been instances where wholesale customers have attempted to roll these transmission rights over for use with competitive providers, as opposed to vertically-integrated utilities. A recent example of a challenge on this issue before the FERC was associated with Williams Energy Company ("Williams") and Southern (FERC Docket ER03-379-001). In this instance, Williams attempted to use the rollover rights of Oglethorpe Power Corp to carry power over Southern's system. While Southern attempted to impose a number of stringent conditions on the transaction, they were ultimately overruled by the FERC. So, FPL's position that the benefits of the transmission rights are limited to just this transaction with Southern does not appear to be correct. These rights could be transferred to other competitive providers in the potential flow path of the transaction. So the Company could at least attempt to maintain these benefits even if they enter into a competitive bidding process.

Q ARE THERE ANY OTHER NON-UTILITY GENERATION RESOURCES THAT ARE LOCATED IN THE GENERAL VICINITY OF THE UNITS TO WHICH THE CONTRACTS ARE TIED?

A Yes. Exhibit DED-2 shows that there are at least 5 existing generators that are in very close proximity to those units from which the Company is getting its power under the proposed Southern PPAs. These generators have a total capacity of 2,600 MW. Although a number of these units may be under contract, or unavailable as a supply alternative, the fact highlights that there are a number of competitive alternatives in the region for which the Company has made only a cursory review.

Q WHAT IS THE COMPANY'S BASIS FOR THE GAS TRANSMISSION BENEFITS ASSOCIATED WITH THE PROPOSED PPA CONTRACTS?

A According to the Company, Southern will use its firm transportation service on Southern Natural Gas Company ("SONAT") to serve the plants supporting the proposed PPA agreements. Southern will give priority scheduling for firm transportation to the natural gas facilities serving FPL and cannot "cancel or replace the existing firm gas transportation contracts without FPL's consent." [Hartman Direct Testimony, 13: 13-14.] The Company believes the gas-related benefits of these contracts are twofold: (1) they increase the diversity of firm gas transportation to the Company; and (2) they increase gas transportation availability for other transportation users in Florida.

Q DO YOU AGREE THESE ARE IMPORTANT BENEFITS?

A Not entirely, and even if there are some benefits associated with these firm gas transportation contracts, they would appear to be minimal, at best. Further, it is not clear how these benefits are unique to the proposed PPAs with Southern. If the Company has some need for firm gas transportation diversity, they could easily detail provisions of this nature in a future solicitation to the market. Merchant generators are located throughout the southeast, on a variety of pipeline systems, and have the opportunity to offer similar provisions in proposed contract submissions. Further, since the Company has not conducted an RFP process in this proceeding, it is impossible to determine if the nature of these benefits are unique.

Q IS FIRM GAS TRANSPORTATION AVAILABILITY PERCEIVED TO BE A PROBLEM IN FLORIDA NOW?

A Historically, Florida has had limited gas transportation infrastructure. The two major pipelines include Florida Gas Transmission ("FGT") and the relatively newer Gulfstream Pipeline System ("Gulfstream"). Currently, these systems have some 3.3 billion cubic feet per day ("Bcf/d") import capabilities. The state's 2003 total natural gas use is estimated to be 2.75 Bcf/d. Thus, while peak day requirements may be higher, utilization of these pipelines right now is somewhere around 80 percent. The real issue, however, is not what these utilization levels are now, but what they will be around 2010.

Q DO YOU SEE THE OPPORTUNITIES FOR NATURAL GAS SUPPLY AND TRANSPORTATION DIVERSITY IN FLORIDA INCREASING OR DECREASING PRIOR TO 2010?

A Actually increasing. As seen in Exhibit DED-3, there are a number of proposed pipelines and pipeline extensions in Florida that should be on line prior to 2010. These include two potential expansions of the Gulfstream project, and three new lines moving liquefied natural gas ("LNG") from the Bahamas to Florida. Combined, these lines should have the ability to move an additional 2.7 Bcf/d into the state. The FPSC Staff's most recent Ten Year Site Plan review anticipates total statewide natural gas demand to be around 3.48 Bcf/d by the year 2012. If this demand forecast is accurate, then there will be, on average, some 2.54 Bcf/d of excess capacity by 2012.

Q THE COMPANY HAS NOTED WHAT IT PERCEIVES TO BE A NUMBER OF "OTHER" IN-STATE BENEFITS ASSOCIATED WITH THE PROPOSED PPAS, BUT AREN'T THERE A NUMBER OF IMPORTANT ECONOMIC BENEFITS ASSOCIATED WITH ENCOURAGING IN-STATE GENERATION?

A Yes. Power generation facilities represent major capital investments regardless of whether they are developed by regulated utilities or merchant generators. Typically, these facilities can create three types of benefits: the one-time economic benefits associated with the construction of a facility; the ongoing economic benefits associated with the operation of a power generation facility; and the lower cost power generated from more efficient generators. It is not

uncommon for typical projects to create hundreds of construction jobs, increased regional economic output, and increased tax collections, particularly property taxes in the county where the power plant is located. Additionally, the wages associated with these facilities are typically higher than average and can be as high as $60,000 per year.

Q WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THIS?

A I would argue that accepting the Company's proposed PPAs, as they have been presented in this proceeding, makes both bad regulatory policy and if the Commission is interest in "other" benefits, then it would be bad economic development policy. From a regulatory policy perspective, the contracts are admittedly a higher-cost resource than FPL's own self-build option and have not been subjected to a competitive bidding process.. From an economic development perspective, if the goal for securing power is to maximize a number of "other" in-state benefits, then it is not clear why the Commission would want to sign contracts that support higher cost resources in another state, when it could promote either a self-build option, or a merchant generation option in Florida and capture the benefits associated with the development of those resources, in addition to lower cost electricity.

VII. THE COMPANY'S REVIEW OF THE MARKET DOES NOT APPEAR TO BE COMPLETE AND INCLUDES A NUMBER OF ERRORS

Q IS THERE A CONSIDERABLE AMOUNT OF MERCHANT CAPACITY DEVELOPMENT IN SERC?

A Yes. It is a well-recognized fact that SERC is one of the most highly developed regions for merchant generation in the U.S. Exhibit DED-4 shows this development with a map of existing merchant facilities in the SERC region. Currently, there are 56 non-peaking merchant facilities with 30,537 MW of generation capacity in the SERC region. In addition, there is 13,259 MW of capacity that is under construction or planned for the next 5 years.

Q IS THIS DEVELOPMENT EVEN THROUGHOUT SERC?

A No, as shown in Exhibit DED-5, there are four sub-regions in the SERC: Entergy, Southern Company, the Tennessee Valley Authority ("TVA"), and the Virginia-Carolinas Reliability Region ("VACAR"). Currently, the Entergy sub-region has 12,934 MWs of non-peaking merchant generation capacity, the Southern Company subregion has 7,548 MW, the TVA subregion has 4,882 MW, and the VACAR subregion has 5,137.

Q HOW MUCH MERCHANT DEVELOPMENT HAS TAKEN PLACE IN FRCC?

A Currently, there are 19 merchant plants with a total of 6,170 MW of generating capacity operating in the FRCC region. When these resources in FRCC are combined with those available in the SERC, there are some 75 merchant plants with a total of 36,707 MW of generating capacity in the southeast. A map of the FRCC development has been provided in Exhibit DED-6.

Q HOW MUCH MERCHANT GENERATION HAS BEEN IDENTIFIED BY THE COMPANY IN THE SERC REGION?

A The Company has identified some 21,800 MW of merchant capacity that is available in the market, and could serve as a potential candidate to serve its resource needs. This is almost 60 percent lower (14,907 MW) than the amount of non-peaking merchant capacity identified as being active in the region by the U.S. Department of Energy and summarized in Exhibits DED-4 and DED-5.

Q WHAT IS THE DIFFERENCE BETWEEN YOUR ANALYSIS AND THAT OF THE COMPANY?

A The Company's initial analysis excludes a number of areas in the southeast and appears to focus on a select number of generators on the TVA border and within the Southern Company and Entergy sub-regions. For instance, the merchant facilities in the non-FRCC region of Florida are excluded, as well as the merchant facilities in VACAR and FRCC. While merchant facilities located in VACAR are some distance away, it is not plausible to assume all of them cannot, or do not, have firm transmission into-SERC from which they could then serve FPL. Further, it is not clear why plants located close to home (i.e., in Florida) have not been considered as potential candidates to meet the Company's resource needs.

Q HAS THE COMPANY RULED OUT A LARGE NUMBER OF THESE FACILITIES AS BEING INELIGIBLE TO SERVE FLORIDA LOADS?

A Yes. The Company has ruled out a large portion of the available generation in the southeast as being located in areas that are "transmission constrained." The Company has not identified the nature of this constraint, failed to offer any studies or analysis to support its assertion, and has assumed that

none of the generators in the region have the ability to get around this constraint. As a result, some 16,400 MW, or 75 percent of all generators identified as being available by the Company in the southeast, are taken off the table as being candidates to serve the FPL's resource requirements.

Q WERE THERE SOME OPERATING UNITS OMMITED?

A Yes, some of these facilities which FPL omitted include Santa Rosa (236 MW), Wansley (1,066 MW), Effingham (490 MW), and the large cogeneration project in Plaquemine (859 MW). The Company has also excluded at least one solid fuel option – the Big Cajun 2 unit (1,730 MW) in Louisiana.

Q ARE SOME OF THE UNITS IN THE COMPANY'S ANALYSIS MISPLACED?

A Yes. Plant Daniel (2,136 MW) is located in southern Mississippi in the Southern Company sub-region, not what the Company is representing as the constrained Entergy sub-region. Hog Bayou (230 MW) is located north of Mobile, Alabama, and is in the Southern Company sub-region, not what the Company represents as the constrained Entergy sub-region. These two plants alone, amounting to a total of 2,366 MW, increases the set of "non-constrained", "viable alternatives," facilities available to serve the Company by some 45 percent.

Q DOES THE COMPANY CONSIDER ANY MERCHANT FACILITIES THAT ARE CURRENTLY UNDER CONSTRUCTION?

A No. In addition to existing merchant generation that has been completed and is in operation,, a number of merchant generators are located in the SERC

region, currently under construction, and scheduled to come on-line prior to 2010. Exhibit DED-7 provides a map of these facilities throughout the southeast. Currently, 6 facilities are being constructed in the region, amounting to 4,542 MW of potential capacity that could serve FPL loads. Some 45 percent of that under construction development is located in SERC, and outside of the areas the Company considers "constrained."

Q ARE THERE ANY OTHER POTENTIAL MERCHANT CANDIDATES IN THE REGION THAT COULD SERVE FPL?

A A number of merchant facilities are considered to be "under development" in the SERC region. Some of these facilities are speculative at this time, and given current market conditions, are probably not likely to get built without some kind of firm contract for the plant output. Nevertheless, they do represent potential opportunities for the Company, especially when one considers that the energy and capacity represented by the PPA is not to be delivered until June 1, 2010. As shown in Exhibit DED-8 currently, there are 12 facilities under development in the southeast, amounting to approximately 8,717 MW of capacity.

Q SO DO YOU SEE GENERATION MARKETS IN THE SOUTHEAST AS BEING LIMITED?

A No. All told, there is considerable existing development, and potential development, in this market. Exhibit DED-9 combines all of the types of facilities discussed earlier into one map.

Q IN ITS MARKET ANALYSIS, THE COMPANY HAS NOTED THAT MANY AREAS OF THE SOUTHEAST, PARTICULALRY THOSE IN THE ENTERGY SUB-REGION, ARE TRANSMISSION CONSTRAINED. DO YOU AGREE WITH THIS ANALYSIS?

A Not entirely. The Company has summarily removed some 16,400 MW of competitive merchant capacity from its analysis because these facilities are located within areas that are currently transmission constrained (or not on the Southern Company system). Based upon the Company's analysis, these constrained facilities represent some 75 percent of all available merchant generation in the southeast. Of particular note is the fact that virtually every merchant power plant in the Entergy sub-region of SERC has been taken off the table for consideration by the Company. This is important since the Entergy sub-region accounts for 42 percent of all merchant generation in the SERC region.

Q DO YOU THINK THE ANALYSIS IS REASONABLE?

A No. I do not believe this is reasonable for a variety of reasons. First, the Company has failed to specifically identify, or offer real evidence about the types of problems that are constraining the delivery of merchant generation from the Entergy sub-region to Florida. It appears the Company assumes that all generators in that region are subjected to the same constraint. Second, the Company's analysis is static and based upon problems that even if accepted, are based upon operating conditions today, not in 2010.

Q DO YOU FORESEE CONSIDERABLE INVESTMENTS IN SERC TRANSMISSION INFRASTRUCTURE OVER THE NEXT SEVERAL YEARS?

A It would appear that way. The most recent report provided by the North American Electric Reliability Council ("NERC") indicates that SERC will be the fastest growing region in North American for transmission investments. For instance, Exhibit DED-10 shows the proposed increases in the circuit-miles of transmission lines, with voltages of 230 kV and greater, over the next several years. SERC will be growing by over 8 percent over the next decade. Almost 1,350 miles of new transmission is proposed for construction through 2008, with an additional 1,085 miles being added between 2009 and 2013. The total forecasted investment over the next decade could be as great as 2,434 miles. In fact, transmission investments in the SERC represent close to 50 percent of all forecasted additions in the U.S. over the next decade.

Q WHAT ABOUT THE FRCC?

A Growth in transmission investments in FRCC, while not as considerable, is still relatively substantial. NERC forecasts show that the FRCC transmission could increase by 6 percent by adding 360 circuit miles of transmission lines by 2008, and an additional 81 circuit miles by 2013. Growth in transmission investment in FRCC is third behind MAIN and SERC on a relative basis.

Q HAS THE COMPANY COMPARED THE PROPOSED CONTRACTS WITH ANY OTHER CONTRACTS?

A **The Company claims that it has compared the proposed contracts with** three publicly available sources of information. These include:

(1) Actual sales associated with the Tenaska Lindsey Hill project;

(2) Actual sales associated with the Central Alabama unit; and

(3) A proposed sale between Southern Power Company and one of its affiliates (Georgia Power) that requested approval before the FERC in Docket No. ER03-713-000 (hereafter "Southern Power-Georgia Power" contracts).

Q DO YOU THINK THE COMPARISONS BETWEEN THE TENASKA AND CENTRAL ALABAMA UNITS ARE COMPARABLE TO THE COMPANY'S CURRENT PPA PROPOSAL?

A No. It is not clear if this sale represents a true "apples-to-apples" comparison. FPL's comparison is ambiguous, and is remarkable for its lack of documentation and detail. It would appear from the Company's discussion that the capacity values with these sales may actually be lower than the proposed PPAs in this proceeding. But, as the Company notes, the purchase amounts are higher when the respective operating conditions are taken into consideration. While this difference could be related to potential heat rate differentials, the Company is entirely ambiguous on: (1) what the operating differences really are; (2) how substantial those differences are; and (3) how they are adjusted for a 2010 delivery date.

Q ARE THE SOUTHERN POWER-GEORGIA POWER CONTRACTS NOTED BY THE COMPANY A VALID COMPARISON?

A No. These contracts, which were submitted to the FERC for approval, were very controversial. Several interveners to the proceeding claimed that Southern Power was given preferential treatment in the award due to its affiliate status. Ultimately, Southern decided to withdraw its application for approval of

the contracts from the FERC. Thus, these contracts should not be used for comparison purposes since (1) the legitimacy of the bids was questioned and (2) the contracts were never completed and ultimately withdrawn.

Q NOTWITHSTANDING THE VALIDITY OF THESE CONTRACTS, DO YOU THINK THE APPROACH THE COMPANY USED TO MAKE ITS CONTRACT COMPARISONS IS VALID?

A No. While I have not had the opportunity to see the pricing terms associated with the proposed PPA in this proceeding, and here again the Company's analysis is somewhat ambiguous. There appear to be at least some obvious inconsistencies in the approach the Company has used in comparing its PPA proposal with (1) the Southern Power offers, and (2) the other "expression of interest" that the Company solicited from the market.

Q WHY DO YOU THINK THE COMPARISONS ARE INCONSISTENT?

A In comparing the Southern Power-Georgia Power offers, the Company takes the reported capacity prices and, I believe, escalates these by the contract inflation factor of 3 percent to determine a future year capacity price of $7.28/kW-month [Hartman Direct Testimony, 18:17.] In this analysis, the Company completely ignores the energy component of this contract. However, in its later comparison of the offer submitted as an "expression of interest" the Company appears to acknowledge that the capacity component of the bid from the market is lower, but that the heat rate portion is higher, and is therefore, above the proposed PPA in this proceeding. The two approaches do not appear to be valid comparisons: if the total contract approach is the most valid, then the Southern

comparison is incomplete because the energy terms of the arrangement are unknown. If a capacity value approach is the most valid, then the Company was offered a better deal in the market, but failed to act on it, and has proposed to accept the proposed Southern PPAs instead.

Q ARE THERE ANY OTHER PROBLEMS WITH THIS ANALYSIS?

A Yes. In recent RFPs, the Company has required a number of different factors to be considered in evaluating individual offers from competitive merchant providers. These have included adjustments associated with dual fuel capabilities; geographic preferences (line losses from resource locations in various parts inside and outside the state); and the impact the resource would have on must-run units in South Florida. It is not clear to what extent these factors have been taken into consideration in its analysis.

Q WHAT OTHER COMPARISONS HAS THE COMPANY MADE?

A The Company made an additional attempt to evaluate the costs from a RFP in 2003. This analysis has been provided in Exhibit TLH-6, and according to the Company, is an economic comparison of proposed PPAs and "the most comparable offer from the 2003 RFP (a 1,220 MW 15 year PPA)." [Hartman Direct Testimony, 19: 19-23.]

Q WHAT ARE YOUR CONCERNS REGARDING THIS EVALUATION?

A I have several concerns regarding this analysis. The first is that the amount of capacity represented by the PPA is different and may be met by a combination of units that were previously unavailable. The second is that the RFP had a different time horizon for both the build-out and the term of supply.

The third is that additional capacity may be available that has come on-line since that time or is under construction or development at the current period. The fourth is that the Company has used "current economic assumptions" which may not be representative of the conditions that competitive providers used in the RFP process completed a year ago. Companies continuously update and modify their business plans, and to assume current economic conditions may be limiting.

Q DO YOU HAVE ANY "BIG PICTURE" CONCERNS ABOUT THE OVERALL COMPARISON ANALYSIS CONDUCTED BY THE COMPANY?

A Yes. The nature of the entire analysis is very "thin" – there are just not a lot of data points in which to compare the Company's proposed PPA. I do not believe this gives the Commission a very solid nor comfortable basis from which to approve this decision. There would appear to be only one transaction that is perhaps the most direct comparison in this proceeding coming from the Company's reported "expression of interest." The Company has noted that it believes it has received a limited response to its inquiries because of the timing of the interest is so well out into the future (2010). [Hartman Direct Testimony, 19: 5-8.] If this is the case, then the Commission would benefit by suggesting that the Company issue a RFP to the market to compete for the energy and capacity represented by the PPA proposal at some future date.

Q BUT THE COMPANY INDICATES THAT THE COMMISSION MUST ACT NOW IN ORDER TO ATTAIN THE POTENTIAL PPA BENEFITS. DO YOU AGREE?

A. No. The Company indicates that it must act now to secure the "other benefits" articulated in its proposal. [Hartman Direct Testimony, 19: 12-14.] Even if the Commission accepts that these benefits are substantial, which is questionable, the Company has provided no concrete or compelling evidence that these benefits will not exist in the future. The Commission should take its time and prod the Company to subject the offer to a formalized competitive bidding process to ensure that the full breadth of the market has been considered for the benefit of ratepayers.

VIII. SUMMARY AND RECCOMENDATIONS

Q COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A I recommend that the Commission separate the cost recovery issue for three purchased power contracts with SCSI from the remaining issues in this fuel docket for the following reasons:

(1) The proposed purchased power contracts represent a considerable commitment for FPL that extends well into the future. The proposal raises numerous complex issues that should not be considered on a relatively expedited basis.

(2) Because of the magnitude of this request, the terms, conditions, and rates for these proposed contracts should be compared to the best alternative available in the market. The Company has not conducted a RFP process as envisioned in the FPSC Rule 25-22.082; therefore, the Commission cannot be assured that this resource proposal is the most cost effective available in the market

for ratepayers. In fact, the Company has admitted that its self-build option is some $60 to $80 million lower than the contracts proposed in this proceeding. [Hartman Direct Testimony, 15: 17-18.]

(3) The extent to which the Company has queried the market is questionable. Further, a number of the "additional benefits" associated with these contracts are likewise questionable and should be reviewed carefully. If the Commission wishes to have the Company seek these types of additional benefits, after satisfying itself that the benefits are significant enough to outweigh cost savings, the benefits specifically sought should be written into the requirements of a competitive proposal submitted to the market.

(4) Separating this issue would not appear to harm ratepayers since the Company has noted that its current contract terms with Southern allow for the longer of 6 months for regulatory approval or securing transmission rights. [Hartman Direct Testimony, 6:17-18.]

(5) Separating this issue from the remaining issues in this docket, and considering it in a more thorough manner by testing the new contracts against the competitive market through an RFP process, would serve the public interest by ensuring "that a public utility's selection of a proposed generation addition [inside or outside of Florida] is the most cost-effective alternative available." [F.A.C., FPSC Rule 25-22.082]

Q DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A Yes. If the Commission rejects my primary recommendation to separate the issues associated with the Company's proposed PPA from this proceeding, then I would recommend that the Commission not approve the Company's proposed PPAs. I base this alternative recommendation on the following points:

(1) The Company has not conducted a thorough competitive bidding process for these resources.

(2) The Company has not provided complete and detailed information in its filing to prove that these PPAs are the least cost option available to ratepayers.

(3) The Company has indicated that its self-build option is a lower cost resource than the proposed PPAs. The purported additional benefits associated with the Company's proposed PPAs do not offset these potential costs savings for ratepayers. The Company should be required to compare this self-build option to all potential contracts and resource alternatives in the market through a competitive bidding process.

(4) FPL has failed to establish the urgency or need to approve now a PPA that calls for delivery of energy and capacity 6 to 11 years from this summer.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY FILED ON OCTOBER 4, 2004?

A Yes it does.

BY MR. MOYLE:

Q Mr. Dismukes, have you prepared a summary of your testimony today?

A Yes, sir, I have.

Q Would you please provide it to the Commission?

A Yes. Good afternoon, Mr. Chairman, Commissioners.

The purpose of my testimony this afternoon is to address the three proposed purchased power agreements that have been offered by Florida Power and Light that they have entered into with Southern Company. I have two recommendations; a primary recommendation and an alternative recommendation in my testimony. The primary recommendation is that you move this issue into a separate proceeding for further investigation. My alternative recommendation, however, would be that if you reject the primary recommendation, would be to reject the company's proposals.

I have three basic concerns with the purchased power agreements that I have outlined in my testimony. The first is that these PPAs have not gone through the competitive bidding process. And even though the competitive bidding process is not explicitly outlined in the Commission's rule, I think the failure to take such a large resource need to the market is at least not in the spirit and keeping with some of the goals that are outlined in that rule.

Secondly, the company to their credit has

acknowledged, I think, that there are some 60 to 80 million, or I think that number has been changed to 69 to $94 million that would be a lower-cost option by choosing their self-build option as opposed to entering into these agreements. And I think that is an issue that ought to be explored a little bit further in another proceeding, as well. Obviously as it stands right now, you have got firm quantifiable dollars that are there that have been recognized as being a benefit to customers by going with that self-build option as opposed to the purchased power agreements.

Now, the company has noted, and I have outlined some issues that I have with these other benefits that they argue more than offset the 69 to 94 million that arise from the self-build option. And some of the problems that I have outlined with a number of these other benefits is that there are no quantitative measures to these benefits explicitly. They are, as I think the company has acknowledged, as I have acknowledged in my testimony, subjective in nature. They have failed to really explain why these benefits or some of these benefits couldn't be obtained through a competitive bidding process.

And lastly, they have not explained why, I think in any firm detail, these wouldn't be available by waiting until a future date closer to the need for these renewals of these contracts.

In conclusion, I would like to recommend that the Commission either spin this off for further investigation or to reject the proposals as they have been offered by the company. I think a good deal of the benefits that are really backing up these contracts and the recommendations for approval for these contracts are subjective in nature, and I would argue that that is one of the reasons for having a competitive bidding process is to move away from some of these subjective determinations to a more level playing field and a more objective framework and quantifiable framework for evaluating resource acquisitions.

Thank you for the opportunity to give you this direct summary.

CHAIRMAN BAEZ: Tender the witness?

MR. MOYLE: The witness is available for cross.

CHAIRMAN BAEZ: And I want to -- Ms. Christensen, I am just going to check with you and make sure that you have no cross.

MS. CHRISTENSEN: No questions.

CHAIRMAN BAEZ: And you all are sponsoring, co-sponsoring so you don't. Mr. Butler.

MR. BUTLER: Thank you.

CHAIRMAN BAEZ: It's hard to keep track without a program.

MR. BUTLER: Thank you, Chairman Baez. Before I start my cross-examination, FPL would like to enter into the

record as an exhibit to the hearing Doctor Dismukes' deposition transcript. The same issue will come up with respect to Mr. Vogt and Mr. Knauth, so perhaps we can address this now once and for all.

We feel that pursuant to Rule 1.330 of the Florida Rules of Civil Procedure that for a witness, such as Doctor Dismukes, who is being offered as an expert or skilled witness that we have the right to have his deposition entered into the record of this proceeding. It will allow us to greatly simplify, streamline, and shorten the extent of our examination of not only him, but the other two witnesses. We really just have a few questions we would like to cover live if we can use that process. And so I would, at this point, ask that Doctor Dismukes' deposition transcript be identified as an exhibit, which I believe would be 71.

CHAIRMAN BAEZ: And at this point I'm assuming there is no objection to entering -- to offering up the deposition transcript, but now is your chance.

MS. KAUFMAN: I will let Mr. Moyle speak to Doctor Dismukes' deposition transcript, if that is all right. But is that all we are considering at the moment? I heard Mr. Butler mention the other two witnesses.

CHAIRMAN BAEZ: If I interpreted Mr. Butler's statements correctly, it is a request that he is planning on making for the succeeding witnesses, although for purposes of

proprietary it is not something that we would take up without the witness actually being on the stand. But I guess it is sort of -- these requests are going to be coming. Is that fair, is that accurate, or --

MR. BUTLER: That is accurate.

CHAIRMAN BAEZ: Unless I'm missing something, you know, we will take them up in order.

MR. BUTLER: That would be fine. I was really just trying to do something to speed it up if we could resolve this question of admissibility of the deposition transcripts. If not, if you want to do them just as each witness comes on, that is fine, too.

CHAIRMAN BAEZ: And, again, I'm not aware of anything that would prohibit us from doing it unless someone wants to stop me. Do you want to take the question up now? If you all have objections or want to have a discussion on it, let's do it now.

MS. KAUFMAN: Well, I'm happy to discuss it in the context of Mr. Knauth and Mr. Vogt. We would have an objection to their depositions being entered. They are here, they have been here, and they are prepared to testify. I think Doctor Dismukes is in a different category, if you will, of witnesses, and I will let Mr. Moyle address it if there is any objection to his deposition.

CHAIRMAN BAEZ: And I will hold yours --

MR. MOYLE: And with respect to speeding things up, I am all for that, and hopefully we can wrap this thing up. I guess the concern that I do have is that Mr. Dismukes during his deposition was asked questions about a whole lot of things that have nothing to do with issues in this case. I'm a little reluctant to agree that that information is admissible and comes in just sort of summarily as a matter of fact.

MR. BUTLER: That is the purpose of objections at the deposition.

CHAIRMAN BAEZ: Yes, and I guess having the entire deposition transcript, I think that is one of those that falls into that category of we will give the questions the weight that they deserve. I mean, I'm not really -- I can't tell you I would be concerned if there were questions that are objected to and --

MR. MOYLE: My thinking. In depositions, what is capable of being asked in a deposition is much broader as compared to what is capable of being asked and admitted into evidence at a trial. Depositions are used to query about information that could lead to the discovery of admissible evidence, it is a very broad net. You know, FPL threw a very broad net, and my hesitation is just to have all of that information come in sort of as evidence I don't think is appropriate.

With respect to the point about you have to object,

it is my understanding that you need to object to preserve opportunities like questions of the form of the question, compound questions, things like that to preserve that objection at trial. But your obligation to object at a deposition is not to do so and then say, well, this is irrelevant and it is not coming in because it is irrelevant, there is no issue in the case that any of these questions you are asking goes to. And I don't mean to make it difficult, but --

CHAIRMAN BAEZ: No. I mean, you are raising an objection, and I want to explore this, because I guess I'm trying to get my hands on it. Is it your position that you are waiving any ability to, you know, object or even grounds on appeal that there was any mistake in interpretation or that we took -- we didn't have competent evidence, or we didn't base it on -- any decision that we might make is based on competent evidence, at which time you would have a chance to raise, look, they are using deposition transcripts as a basis, how wide a net it was cast, and whether these facts are relevant or not. I mean, is that where I hear you coming from?

MR. MOYLE: A couple of reasons. It has always been my understanding that with respect to use of a deposition that certain times, you know, you could make use of it, but one was not when a witness was here. Because, otherwise, why call witnesses, you would just put their depositions in. The guy is here, he is able to answer any questions. And I recognize Mr.

Butler's point about time. Mr. Butler and I have had a conversation. You know, I did not know that this issue was coming up until five minutes ago.

He has pointed out a provision in the Florida Rules of Civil Procedure that seems to allow, possibly, for the use of a deposition of an expert in a manner that is different from the use of a deposition of a lay witness. And I don't know if there are any cases interpreting that. I don't want to just waive that objection. But the real concern is there is a lot of stuff in here that they were kind of fishing around and trying to get into a lot of stuff that is not even relevant to the case, and I just don't want that to come in without registering an objection.

CHAIRMAN BAEZ: Okay.

MR. BUTLER: Chairman Baez, may I respond?

CHAIRMAN BAEZ: Please.

MR. BUTLER: First of all, let me just state for the record specifically what I'm referring to. This is Rule 1.330(c)(3) of the Florida Rules of Civil Procedure, and it is interesting because generally (3) deals with the deposition of a witness, whether or not a party -- may be used by any party for any purpose if the court finds, and then there are (a) through (f) subparts. And pretty much (a) through (d), or (a) through (e) have to do with subjects where the witness isn't available or there is a problem with making the witness

available, et cetera. But in contrast, (f) has nothing to do with availability, it is just the witness is an expert or a skilled witness.

I mean, that is the deal. That is the understanding under the current Rules of Civil Procedure in the State of Florida that you may use the transcript from the deposition of an expert in a proceeding irrespective of the availability of the witness. If you have problems with what the scope of the deposition is, then people object. There are, in fact, objections in the transcript of Doctor Dismukes' deposition.

And if the Commission considered, you know, those questions to have been validly objected to, I would expect that you would disregard whatever answers were given to those questions. But the great majority of the questions aren't objected to on, you know, relevance or any other ground. And I think it is not only usable, but I'm entitled to use it in this proceeding for the purpose of constituting testimony of Doctor Dismukes. And, again, it has the benefit of summarizing two hours and ten minutes worth of testimony.

CHAIRMAN BAEZ: Ms. Kaufman, you had mentioned from the perspective of your witnesses and I know that you registered an objection, can I hear your grounds again, please?

MS. KAUFMAN: Yes, Chairman Baez. First of all, looking at the rule that Mr. Butler has cited to you, it says that the deposition may be used by any party for any purpose.

It doesn't say automatically that the deposition is entitled to come into the record. And to speak for a moment to Mr. Dismukes' deposition, which I attended, as he is cosponsored by FIPUG, I agree with Mr. Moyle that there is a lot of information in there that if those questions were asked today would be objectionable, and perhaps you would rule were not appropriate.

As to the other two FIPUG witnesses, I don't think that under this rule it is appropriate to enter their deposition into the record. They are here and prepared to stand for cross-examination and that is the procedure that typically the Commission follows.

CHAIRMAN BAEZ: And just so that I am clear as to Subsection (f), you are denying that they are experts, that even under a liberal interpretation of that term that they don't qualify as experts such that there may even be a question as to the use of their deposition?

MS. KAUFMAN: Chairman Baez, they have not been proffered as experts. In circuit court, and even at DOAH, it is my understanding that there is a long procedure that is gone through to qualify witnesses as experts or not experts. It has been my experience in practicing here that the Commission does not go through that procedure, and this is the first time I have ever heard it suggested.

CHAIRMAN BAEZ: I may be inclined to agree with you,

having sat in several hearings, perhaps not as many as you all, and I don't mean that in any way but that there is not a whole lot of voir dire or challenges. There may be the odd challenge to someone's expertise, but I want you to be very clear because I think what Mr. Butler is suggesting is that his interpretation of that rule is that it creates an opportunity, and now can we agree or disagree, but that based on the witness' expertise or status as an expert, that that creates some -- now, if you have a discrepancy or you have some kind of disagreement about that, I want you to tell me, because then I'm dubious as to what the purpose of the presence of your witnesses are, in fact. Are they experts or not?

MS. KAUFMAN: They are not being proffered as experts. They are being proffered to describe to the Commission what their understanding is of the industry in which they work and how they look at the marketplace. They are not being proffered as an expert, for example, in transmission planning. That might be an area that I guess there has been some discussion about. They are not being proffered in that area. They are simply being proffered to bring to you their perspective in regard to what FPL has or has not done according to their own knowledge in regard to the contracts that you all are dealing with in this case.

CHAIRMAN BAEZ: All right. Ah, Mr. Melson is in the room. The stall worked.

Mr. Melson, would you aid the chair at this point? Have you heard enough of the discussion, or would you like to ask me a question that maybe I can --

MR. MELSON: I have heard pieces of it.

CHAIRMAN BAEZ: There is a rule, and I will cite it to you, it is 1.330(c)(3). Mr. Butler claims that Sub (f), is it?

MR. BUTLER: That's right.

CHAIRMAN BAEZ: Sub (f) creates an opening, and they are proffering or they are asking to admit the deposition transcripts of the three remaining witnesses, or at least the three witnesses being offered by FIPUG and Mr. Churbuck. And for that reason, they want to seek admission of those depositions.

MR. MELSON: And as I read that rule, if the witness is an expert or skilled witness, and I don't know what skilled witness in that context means, it looks as though the deposition is admissible for any purpose.

I did hear another piece of conversation, though. Mr. Butler seemed to indicate that there had not been relevancy objections at the deposition and, therefore, it was too late. Relevancy is an objection that you do not have to make at the time of the deposition. And if you look at Subsection (b) of this rule, objections to relevancy are proper at the time the deposition is offered. So there could be objections beyond

those that were made during the deposition that the Commission could entertain at this point.

CHAIRMAN BAEZ: And that was going to be -- well, yes, but as a practical matter how would we deal with -- I mean, let's say in a perfect world how would we preserve the information, the relevant information that I'm sure Mr. Butler wants to get before the Commission and the, quote, irrelevant information that Mr. Moyle would normally object to?

MR. BUTLER: Chairman Baez, every so often it is like the perpetual motion machine, efficiency plans are too good to be true. I think this is one of those examples. And we will withdraw our request, and we will just do what we need to do, and unfortunately it might take us a little longer. We will still try to keep it short and proceed on that basis.

CHAIRMAN BAEZ: We were just under the wire, because I was going to say we have spent more time arguing over admission of a deposition transcript as we would have spent on cross-exam of the witnesses. And perhaps this is the regulatory equivalent of a war of attrition.

COMMISSIONER DAVIDSON: Just one statement for future reference. I am looking on a line at Chapter 5, Florida Practice, Section 10.8, which states pretty clearly, "However, the deposition of an expert may be admitted in evidence, even if there is no exception that would otherwise support the use of the depo as evidence." So it makes clear what I thought my

understanding was, that if you are an expert it comes in.

CHAIRMAN BAEZ: I understand that. I was looking forward to how Mr. Melson was going to draw that line, but noting Mr. Butler's withdrawal of his request, I think that all becomes moot at this point.

Thank you, Mr. Melson.

MR. McGLOTHLIN: Chairman Baez, forgive me for --

CHAIRMAN BAEZ: Just a point of clarification. Is he withdrawing the request for all witnesses? I don't mean to get --

MR. McGLOTHLIN: No, no. That would have been a good guess, but it is slightly different. This came to us without any preparation time, and the practice before the Commission has been quite different from the practice where experts who typically make their living going from hearing to trial from hearing to trial are first qualified then submitted for voir dire, et cetera.

And so translating this rule to our situation, we don't believe -- we did not intend to proffer FIPUG's witnesses as experts in that sense. However, by the same token, we do think they are proficient and skilled and accomplished in their areas, and I don't want there to be any doubt about their ability to present the testimony that they have prefiled. And for that reason, reserving the objections for another day, we would have no objection to their depositions coming in.

MR. BUTLER: That rings a little hollow coming right after my withdrawal of the request.

CHAIRMAN BAEZ: We are going to get our monies worth out of this hearing it seems to me. Everybody get out their calculators.

Mr. Butler, your witness.

COMMISSIONER BRADLEY: Mr. Chairman, I would like to make a comment before we move on.

CHAIRMAN BAEZ: I'm sorry. Commissioner Bradley.

COMMISSIONER BRADLEY: This very discussion has piqued my interest, and I am just curious as to what is going on. Because I have been under the impression that we, for the last two days, have been listening to experts and people who are proficient and skilled. So not to minimize the importance of all the testimony that we have taken, but have we not been listening to experts and people who are proficient and skilled in the information that they have been passing along to us, or is this now an issue of we have been listening to nonexperts and people who are not proficient, so we don't know if what we have heard is the truth.

CHAIRMAN BAEZ: Commissioner Bradley, I think that you can rest assured that -- nothing has changed in what you have heard in these last few days that you can guess is true or not true to the best of your ability and freedom to do so. Please don't let any of the conversations and findings --

COMMISSIONER BRADLEY: But if we have a witness who is not considered as being an expert and who is not considered as being --

CHAIRMAN BAEZ: I don't believe that is the case.

COMMISSIONER BRADLEY: -- proficient and skilled --

CHAIRMAN BAEZ: I don't believe that is the case and I don't think any --

COMMISSIONER BRADLEY: Is that what I'm hearing?

CHAIRMAN BAEZ: I don't think any of the counsel sitting at the table are going to suggest that in the balance that we have left in this hearing. All we need to do is to just get moving and let's listen to the testimony of the experts on this. And this was --

COMMISSIONER BRADLEY: Is the witness an expert?

CHAIRMAN BAEZ: Will opposing counsel nod yes. You will accept him as an expert?

MR. BUTLER: (Indicating yes.)

CHAIRMAN BAEZ: All right. They are.

COMMISSIONER BRADLEY: Maybe I should ask the witness if he is an expert.

CHAIRMAN BAEZ: You can ask him anything you want.

COMMISSIONER BRADLEY: Are you an expert?

THE WITNESS: Yes, sir.

COMMISSIONER BRADLEY: Are you proficient and skilled?

THE WITNESS: Yes, sir.

COMMISSIONER BRADLEY: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. BUTLER:

Q Good afternoon, Doctor Dismukes, your turn now.

A Okay.

Q I just have a few questions for you, and I really mean that. Who contacted you about testifying in this proceeding?

A Mr. Joe Regnery.

Q And to your knowledge for whom does Mr. Regnery work?

A Mr. Regnery is counsel for Calpine Corporation

Q Have you talked to him today?

A Yes, sir, I have.

Q Is he here?

A Yes, sir.

Q When you spoke to Mr. Regnery initially about your testimony, what did Mr. Regnery ask you to do?

A He called me and asked if I would be interested in reviewing issues associated with Florida Power and Light's proposal before the Commission in this proceeding to get approval for the three purchased power agreements that are under discussion right now.

Q And did he say on whose behalf you would be testifying?

A The first time we discussed, I don't recall him saying one way or another who I would be representing. He did express that, I think, on a second follow-up phone call that I would not be representing Calpine, I would be representing Thomas Churbuck.

Q Did Mr. Regnery say anything to you in either of those conversations about Calpine's position relative to this docket?

A Mr. Regnery outlined some of the positions that had been -- that were up in the air that had been discussed, many of which I think were outlined in the motion to -- in the request to intervene in this proceeding.

Q Anything else?

A I think that was about it.

Q In your deposition, Doctor Dismukes, on Page 28, Lines 6 through 9 --

A Excuse me, what page was that again?

Q I'm sorry, Page 28, Lines 6 through 9. What you see there, I would ask you a question about whether you had conversations with Mr. Regnery and what he had told you. And one of the things that -- or what this says is Mr. Regnery didn't say anything other than in summarizing what their position was. He never told me what impact it would have on Calpine. What did he tell you in summarizing what their position was?

A That they thought that this was a relatively large request that was before the Commission that was being pushed through in a relatively expedited fashion, that there were a number of other factors that ought to be considered in the context of looking at this proposal that made it, to a certain extent, a rush to judgment that created a considerable amount of uncertainty associated with the preapproval, such as issues associated with the ongoing proceedings at the FERC, issues -- well, I think the other big issue was the fact that this had not gone through a competitive bidding process, and some of the other issues that escape my memory right now.

Q You mentioned a minute ago that in one of your conversations Mr. Regnery said you would be appearing on behalf of Thomas Churbuck, is that correct?

A Yes, sir.

Q Okay. When did you first speak with Mr. Churbuck?

A I talked to Mr. Churbuck on the phone about the day before I filed testimony.

Q Okay. Did you provide him with a copy of your proposed testimony?

A It was my understanding that Mr. Moyle provided him a copy of it.

Q Did you talk to Mr. Churbuck about your proposed testimony?

A Yes, sir.

Q Did he make any changes to your testimony?

MR. MOYLE: He being Mr. Moyle or he being Mr. Churbuck?

MR. BUTLER: He being Mr. Churbuck.

A No, sir, not that I recall.

Q Have you had any other communications with Mr. Churbuck since that time?

A No, sir, I have not.

Q And how long would you say that you spoke with Mr. Churbuck at the point when you had this conversation about your draft testimony?

A It was longer than a half hour, but under an hour.

Q Have you ever met Mr. Churbuck in person?

A No, sir, I have not.

Q Is he here today?

A Not that I know of, no, sir.

COMMISSIONER DAVIDSON: I have just one question I want to interject here. Thank you, Chairman.

Who is paying your expert fee, Mr. Churbuck or Calpine?

THE WITNESS: My bills go to Mr. Moyle.

COMMISSIONER DAVIDSON: And for counsel, who is paying that fee, Mr. Churbuck or Calpine?

MR. MOYLE: I'm sending my bill to Mr. Churbuck.

COMMISSIONER DAVIDSON: Well, you know the

information I am seeking. I would like an answer to it at some point.

MR. MOYLE: Yes.

COMMISSIONER DAVIDSON: Thanks.

CHAIRMAN BAEZ: Mr. Butler.

BY MR. BUTLER:

Q Doctor Dismukes, do you have any form of written or oral engagement with Mr. Churbuck?

A No, sir, I do not.

Q Have you ever discussed with Mr. Churbuck whether he would be paying your bills?

MR. MOYLE: Let me just register an objection. I mean, this is information that doesn't go to any issue that I am aware of in the case in terms of the matters in dispute and I think it is irrelevant.

MR. BUTLER: I think it is quite relevant to a contention we consider very important here, which is witnesses who attorneys truly represent what the interests are in reviewing and critiquing the power purchase agreements that are in question in this docket. And I think this goes pretty directly to it. And, frankly, it is pretty directly showing what is going on here, which is that this is a witness who is discussing with and serving the interests of someone other than Mr. Churbuck.

CHAIRMAN BAEZ: Mr. Butler, assume for a moment that

your point is made. Are there questions that you can ask the witness concerning his critique of the project in a substantive manner rather than their point of origin? And, remember, assume for a moment that your point is made.

MR. BUTLER: I will move on.

CHAIRMAN BAEZ: Thank you.

MR. BUTLER: I will also move pretty quickly to the finish to keep this short.

BY MR. BUTLER:

Q Doctor Dismukes, is it true that you have not testified in any Florida Public Service Commission need determination proceeding?

A That is correct, yes, sir.

Q It is also true that you have not testified in any FPSC proceeding concerning the Commission's Bid Rule?

A Yes, sir, that's correct.

Q Have you testified in any FPSC proceeding that involved the review and approval of power purchase agreements for electric utilities?

A No, sir.

Q Have you ever personally been involved in negotiating a power purchase agreement for an electric utility?

A No, sir, I have not.

Q Do you have any experience in financial evaluation or creditworthiness evaluation of electric power suppliers?

A No, sir, I have not.

Q Have you conducted any financial evaluation of the Calpine Corporation's creditworthiness?

A No, sir, I have not.

MR. BUTLER: Thank you very much, Doctor Dismukes. That's all the questions that I have.

MR. MOYLE: I have nothing on redirect.

CHAIRMAN BAEZ: Staff, you don't have any cross?

MS. VINING: We don't have any questions.

CHAIRMAN BAEZ: Commissioners, do you have any questions? Mr. Moyle, do you have redirect?

MR. MOYLE: No.

CHAIRMAN BAEZ: Thank you, Doctor Dismukes. You are excused. Before I excuse you, can we get -- without objection, can we get the exhibits in? I'm showing 49 through 58.

MR. MOYLE: We would move them into the record as evidence.

CHAIRMAN BAEZ: Without objection, show Exhibits 49 through 58 moved into the record. And I am also showing Number 70, which is the errata sheet. If there is no objection, we will have that moved into the record, as well.

(Exhibits 49 through 58 and Exhibit 70 admitted.)

MR. McGLOTHLIN: Chairman Baez and Commissioners, Ms. Kaufman is distributing an errata sheet. FIPUG's next witness is Kerrick Knauth, whose original testimony addressed the

Progress Energy UPS contracts that the purpose of the errata sheet is to identify the changes that would eliminate those references in his prefiled testimony.

CHAIRMAN BAEZ: All right. And as we have done with the previous errata sheet, we will just mark it as Exhibit 71.

MR. McGLOTHLIN: All right.

(Exhibit 71 marked for identification.)

Whereupon,

KERRICK S. KNAUTH

was called as a witness on behalf of FIPUG, and having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q Would you please state your name and your business address, sir?

A Kerrick S. Knauth, 2929 Allen Parkway, Houston, Texas 77018.

Q By whom are you employed, Mr. Knauth?

A Northern Star Generation Services.

Q And for whom do you appear in this proceeding?

A For FIPUG.

Q Did you prepare for submission in this docket some prefiled testimony for FIPUG?

A Yes.

Q Do you have it before you?

A Yes.

Q Do you have any changes, or corrections, or additions to make to the prefiled testimony?

A No, I do not.

Q If I were to ask you the questions that are posed in the prefiled testimony, would your answers be the same?

A Yes, they would.

MR. McGLOTHLIN: I request that Mr. Knauth's prefiled testimony be incorporated into the record at this point as though read.

CHAIRMAN BAEZ: Without objection, show the testimony of Kerrick Knauth inserted into the record as though read, and also note for the record that Exhibit 71 constitutes an errata sheet with corrections to that prefiled testimony.

Mr. McGlothlin.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NUMBER 040001-EI

DIRECT TESTIMONY OF KERRICK KNAUTH

ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP

OCTOBER 4, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kerrick Knauth. My address is 2929 Allen Parkway, Suite 2200, Houston, Texas 77019.

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?

A. I am employed by Northern Star Generation Services Company LLC, which is wholly owned by Northern Star Generation LLC ("Northern Star"). My job title is Asset Manager. In that capacity, I am responsible for the development and commercial aspects of the power generation project owned by Vandolah Power Company LLC, which is also wholly owned (through subsidiaries) by Northern Star.

Q. FOR WHOM DO YOU APPEAR?

A. I am testifying on behalf of the Florida Industrial Power Users Group ("FIPUG"). FIPUG is an ad hoc group of industrial customers that intervenes in

dockets that affect the size of its members' bills. FIPUG favors the use of competition to ensure that ratepayers receive power from the most economical sources available.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE.

A. I received a B.S. degree in Civil Engineering from Tulane University in 1986. Following two years with the United States Peace Corps, I worked as a civil engineer with the United Nations Department of Technical Cooperation for Development. I received an M.A. degree in International Relations, with a concentration in Energy, Environment, Science, and Technology, from John Hopkins University in 1994.

During the period 1994-1998 I was employed as a business developer and project manager for Coastal Power Company. While with Coastal Power Company, I explored and developed power development opportunities in numerous international settings in the Philippines, Southeast Asia, and Latin America.

I then joined Oxbow Corporation. While with Oxbow, I was responsible for the financial management of its geothermal power plants in the Philippines and Costa Rica.

I joined El Paso Corporation in 2001. Among other assignments for El Paso, I became involved with the Vandolah power generation project shortly

before it began commercial operations in June of 2002. When Northern Star acquired certain of El Paso's assets, including the Vandolah project, I accepted my present position.

Q. PLEASE DESCRIBE THE VANDOLAH PROJECT.

A. The Vandolah project consists of four simple cycle gas-fired combustion turbines on a site of approximately 40 acres in Hardee County, Florida. The project, built at an initial cost of approximately $265 million, began commercial operations in June of 2002. The four turbines produce a nominal output of 680 MW of capacity. The project is adjacent to Progress Energy's Vandolah substation, which was the site of the recent addition of a 230 kV transmission upgrade between the Vandolah substation and FPL's Whidden substation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As I mentioned, FIPUG supports wholesale competition as an effective means of ensuring that ratepayers receive the best, most economical electrical service.

Florida Power and Light Company and Progress Energy have asked the Commission to approve several proposed Unit Power Sales contracts with members of Southern Company. On behalf of FIPUG, whose members would be affected by the approval of the proposed Unit Power Sales arrangements, I will

provide comments - from the perspective of a wholesale provider, to be sure - describing why it would be in the ratepayers' interests for the Commission to deny the requests for approval, and direct the utilities to identify and evaluate the universe of alternatives available in the wholesale market (in Florida and elsewhere) prior to determining which options they should pursue.

Q. WHY WOULD TESTIMONY FROM THE PERSPECTIVE OF A SELLER OF WHOLESALE POWER BE RELEVANT TO RATEPAYERS' INTERESTS AND TO THE COMMISSION'S CONSIDERATION OF THE REQUESTS FOR APPROVAL OF THE PROPOSED UPS CONTRACTS?

A. As a seller of wholesale power, Vandolah Power Company LLC has an obvious interest in competing for the opportunity to provide the capacity and energy represented by the proposed contracts. However, Vandolah Power Company LLC - or any other wholesale provider - will be successful only if its product is *considered* and, when compared to alternatives, is determined to be the most beneficial to ratepayers. To the extent any wholesaler capable of meeting all or part of the proposed capacity is not included in the underlying analysis, this omission is directly relevant to the issue of whether the Commission should approve the proposed contracts.

Q. PLEASE SUMMARIZE THE PROPOSED UPS CONTRACTS.

A. As described in the pre-filed direct testimony of Progress Energy witness Sam Waters and FPL witness Tom Hartman, all of the proposed arrangements would begin in 2010 and terminate in 2015, subject to certain possible extensions. FPL proposes to enter three contracts totaling 955 megawatts. Of that amount, 165 megawatts would be generated by a coal-fired generating unit. The balance, or 790 MW, would be generated from combined cycle capacity.

Progress Energy witness Sam Waters says that his company has not yet negotiated definitive contracts with Southern Company. He describes his company's proposal to enter UPS contracts that, when negotiated, would total 425 megawatts, including 74 megawatts of coal-fired capacity and 351 MW of combined cycle generation.

Both utilities shielded the pricing information in the proposed contracts.

Q. SHOULD THE COMMISSION APPROVE THE UPS CONTRACTS, AS REQUESTED BY FPL AND PROGRESS ENERGY?

A. No.

Q. WHY NOT?

A. Collectively, the proposed UPS arrangements total approximately 1400 MW. With respect to both FPL and Progress Energy, each utility's witness testifies that, if the utility were to meet the 2010 need for capacity with units in its

generation expansion plan rather than with the proposed UPS arrangements, it would build a large combined cycle unit. (Waters, page 6, lines 15-16; Hartman, page 15, lines 10-12.) I am informed that before either utility could proceed with construction of such a unit, it would be required by rule to conduct a detailed Request For Proposals, and that its decision would be reviewed in a Commission proceeding that typically lasts for several months (and in which bidders routinely participate as parties.) The nature and significance of the needs that the proposed UPS arrangements are intended to satisfy are identical to those of the needs that would trigger that scenario of active competition and detailed review. Yet, neither utility has performed a meaningful analysis of alternatives available in the competitive marketplace, and both utilities are asking the Commission to make a decision within a severely compressed time frame. Absent a thorough analysis of all competitive alternatives, the Commission is simply not in a position to gauge whether the proposed UPS contracts beginning in 2010 comprise the best alternative from the ratepayers' point of view. Nor, in fact, are the utilities.

Q. HAVE THE UTILITIES JUSTIFIED THE PROPOSAL TO LOCK INTO THE PROPOSED CONTRACTS SIX YEARS PRIOR TO THE DELIVERY OF POWER WITHOUT EXPLORING AVAILABLE ALTERNATIVES?

A. No.

Q. PLEASE EXPLAIN.

A. I will begin with FPL. At page 19, FPL Witness Hartman says the "futures market" for wholesale transactions has only a two or three year horizon. I believe Mr. Hartman has failed to distinguish between energy *brokers*, on the one hand, and wholesale providers who own generating assets, on the other. Pure energy brokers may tend to focus on a "futures market" that typically does not extend beyond the near term. However, a developer who has financed and constructed a generating asset having a useful life of 30 years or more can and most certainly will consider contractual arrangements that extend far beyond the "energy futures" horizon that Mr. Hartman mentions. However, this is only one aspect of the utilities' failure to support their proposals.

Q. PLEASE ELABORATE.

A. The principal observation to be made is that Mr. Hartman does not explain adequately *why* FPL wishes to contract for 955 megawatts of power so far in advance of the time it is needed, when sufficient time is available to consult the market prior to making a decision. This is a serious shortcoming, because a decision made now would not take into account any developments that may impact the wholesale landscape prior to 2010. For instance, there is time to factor into the analysis the extent of progress on the development of an RTO, or any other change that could increase the competitive nature of the wholesale landscape in Florida.

Nor does Mr. Hartman explain why, to the limited extent FPL looked into the availability of wholesale merchant power, FPL considered merchants located in SERC, but apparently did little or nothing to contact potential suppliers in Florida. With respect to the "analysis" of the Florida wholesale market, Mr. Hartman says he picked the most appropriate proposal submitted in FPL's 2003 RFP and adjusted it to represent the present. An outdated bid that is (1) nearly two years old and (2) has been modified - not by the bidder, but by the recipient - is a poor proxy for an indication of the current market as indicated by a solicitation or competitive process - particularly when the alternatives are available to be consulted.

Q. WHAT ABOUT PROGRESS ENERGY?

A. The discrepancies in the approaches used by the two utilities should, in and of itself, lead the Commission to require far more in the way of analysis. Based on Mr. Waters' testimony, it appears that Progress Energy made even less of an effort to identify and assess alternatives in the marketplace. As far as I can tell, Progress Energy compared term sheets being negotiated with Southern (again, there are no proposed contracts at this point) with only its self-build option. Mr. Waters does refer vaguely to some alternative assumptions regarding the cost of economy energy. While this reference is ambiguous, it is clear that Progress Energy did not consult the wholesale market for firm capacity

prior to settling on the UPS proposals now being negotiated with Southern Company.

Q. ISN'T IT TRUE THAT THE WITNESSES FOR FPL AND PROGRESS ENERGY CLAIM BENEFITS THAT WOULD BE ASSOCIATED WITH THE UPS CONTRACTS?

A. Yes. However, the claims are insufficient to justify the proposed UPS contracts.

Q. PLEASE EXPLAIN.

A. For example, the witnesses stress the advantage of maintaining firm transmission rights on Southern's system. As a starting point, and assuming for the moment that there is in fact an advantage to maintaining such rights, it is not clear that the proposed UPS contracts are essential to the ability to acquire such rights. More importantly, whether such firm transmission rights would be advantageous would turn completely on two points: (1) the cost of the firm transmission, which is not known by either utility, and (2) the extent to which the utilities utilize those rights over time to acquire power at prices more favorable than alternatives that do not require such rights-and so do not require the utilities to incur the costs of firm transmission across Southern. FPL and Progress Energy offer no projections or assumptions of the relative merits, and offer no

cost/benefit analysis. Having expressly made the proposed UPS agreements subject to prior Commission approval, the utilities ask the Commission to act in the absence of the cost of firm transmission that the contracts will require - a crucial factor on which the prudence and cost-effectiveness of the arrangements will depend heavily.

Progress Energy's witness, Sam Waters, says that one advantage of the proposed UPS arrangement would be a contribution to "cost certainty." However, the term sheet attached to his testimony indicates that Progress Energy would be responsible for any costs - - including the cost of capital additions - - occasioned by a "change in law." For an existing coal-fired generating unit, this provision creates the potential for a significant increase related to changes in environmental requirements. (One thinks, for example, of the increasing interest of federal regulators in controlling mercury emissions from existing plants.) Committing to the transaction years prior to the time it is necessary to do so would increase the exposure to that risk.

Each potential source of capacity and energy will have its own set of advantages and disadvantages. By way of example, projects located near the load centers of Progress Energy and FPL would have fewer line losses and would cost less to transmit. At the same time they would provide "intangibles" of their own, such as added jobs and tax revenues to the local economy.

To be very clear, with these comments I am not asserting - - and it is not FIPUG's position - - that Vandolah, or any other alternative (including the UPS proposals), should be chosen at this time and based on this record. My point is

that until all of the alternatives available in the market have been fully identified and explored, there is no way of determining whether the benefits claimed for the proposed UPS contracts are superior to other alternatives. There is time to conduct such a comparison, and, given the size and nature of the need for capacity and energy, as well as the number of significant unknowns regarding the proposed UPS arrangements, there are compelling reasons to do so.

Q. DID PROGRESS ENERGY OR FPL CONTACT VANDOLAH POWER COMPANY LLC REGARDING A NEED FOR POWER IN THE 2010 – 2015 TIME FRAME?

A. No.

Q. DOES VANDOLAH POWER COMPANY LLC OWN ANY GENERATING CAPACITY THAT WOULD BE AVAILABLE FOR SALE IN THE 2010 – 2015 TIME FRAME?

A. Yes. The capacity of the Vandolah project is currently subscribed until 2012. Absent a change in Vandolah's current commercial arrangements, it will be available for sale in the wholesale market thereafter.

Q. WOULD VANDOLAH POWER COMPANY LLC BE INTERESTED IN PRESENTING A PROPOSAL TO PROGRESS ENERGY AND/OR FPL IF GIVEN THE OPPORTUNITY?

A. Yes. We are in the business of seeking and responding to all such opportunities to market our power.

Q. DO YOU THINK THE FACT THAT VANDOLAH IS CURRENTLY COMMITTED THROUGH PART OF 2012 WOULD PRECLUDE VANDOLAH POWER COMPANY LLC FROM BEING A CANDIDATE?

A. Not necessarily.

Q. PLEASE EXPLAIN.

A. Conceptually, it is possible for a utility to structure short-term arrangements at the outset of the period in order to avail itself of a wholesale source that is available later in the period. Further, earlier I added the caveat that Vandolah's capacity is subscribed until 2012 unless the commercial arrangements change. A competitive opportunity could also lead Vandolah to consider converting a portion of its capacity to a combined cycle configuration for the purpose of a proposal. Using Vandolah as an illustration, these are some examples of the different dynamics that potentially could be brought to bear in a way that would benefit ratepayers if the utilities were to engage in thorough,

competitive processes prior to committing to arrangements to meet the 2010-2015 need.

Q. WOULD YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Collectively, Progress Energy and FPL propose to enter UPS contracts totaling approximately 1400 megawatts six years before the power is needed, without first soliciting or evaluating alternative proposals and without knowing all of the costs associated with the proposed UPS arrangements.

If one has any faith in the proposition that competition benefits ratepayers, one must believe that competition for large blocks of capacity and energy would benefit ratepayers more. Further, large, discrete increments of capacity - 955 megawatts in the case of FPL and 425 megawatts for Progress Energy - lend themselves to effective competitive processes. These situations are precisely the type in which the opportunity to apply market forces to reduce costs should be maximized, not avoided.

Finally, while FPL and Progress Energy make some quantitative claims in support of their request, neither supports its claims with assumptions or information that would be necessary to evaluate those claims. More time than is available in the compressed hearing scheduling in this docket would be needed to obtain and analyze the needed information. There is no requirement to make a decision on the proposed, multi-year UPS agreements within the confines of the proceeding on the annual cost recovery factors that the Commission must

authorize prior to the beginning of the coming calendar year. I recommend that the Commission defer a decision on the proposed UPS contracts and order FPL and Progress Energy to explore and evaluate alternatives available in the wholesale market before determining the best means of addressing their 2010 needs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. McGLOTHLIN:

Q Mr. Knauth, have you prepared a summary of your testimony?

A I have.

Q Please summarize your testimony for the Commissioners.

A I will. And I apologize. I have a little bit of a cold, so I may pause for water. My testimony supports FIPUG's position that FPL's proposed UPS contracts totalling 955 megawatts should not be approved in this docket because FPL has not yet identified or considered the alternatives available in the wholesale market.

My comments are made from the perspective of a wholesale provider. I oversee the commercial aspects of the Vandolah Generating Project, consisting of 680 megawatts of simple cycle gas turbines located in Hardee County. Vandolah is in the business of competing for opportunities to provide wholesale capacity and energy. My comments are relevant to the UPS issue because Vandolah or any wholesale provider can be successful only if it provides the best deal for ratepayers, and wholesale providers can provide this benefit for ratepayers like FIPUG members only if wholesale opportunities are considered by the purchasing utility.

With respect to FPL's 955-megawatt need in 2010, that hasn't happened. For instance, with respect to alternatives

available in Florida, FPL says it compared the UPS option with a single bid that was submitted to its 2003 RFP. One out-of-date proposal is a poor proxy for the current wholesale market, especially when there is sufficient time to consult available alternatives.

FPL appears to base its support of the UPS contracts and its failure to consider alternatives largely on the benefits claimed for the firm transmission rights that would be associated with the UPS contracts. However, each alternative will have its particular set of advantages and disadvantages.

FPL cannot determine that the proposed UPS contracts are more advantageous on the whole than alternatives that do not involve incurring the cost of the firm transmission rights without first identifying and evaluating the alternatives. To be clear, the purpose of my testimony in this docket is not to advocate that FPL should purchase from any specific source, but to encourage the Commission to direct FPL to explore and consider the wholesale market before determining the option that best serves ratepayers' interests.

Absent a thorough analysis of competitive alternatives, the Commission is not in a position to gauge whether the proposed UPS contracts beginning in 2010 comprise the best option from the ratepayers' point of view, and neither is FPL.

And this concludes my summary.

CHAIRMAN BAEZ: Ms. Christensen, any questions for the witness?

MS. CHRISTENSEN: No questions.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: No questions.

CHAIRMAN BAEZ: Ms. Smith.

MS. SMITH: Natalie Smith for FPL.

CROSS EXAMINATION

BY MS. SMITH:

Q Good afternoon, Mr. Knauth.

A Good afternoon.

Q You are employed as asset manager for Northern Star Generation Services, correct?

A Correct.

Q Northern Star is in the business of owning and operating power plants, correct?

A Correct.

Q So Northern Star is a merchant power company?

A Sorry?

Q Northern Star is a merchant power company?

A Yes.

Q And Northern Star has been in the business of owning and operating power plants since January of this year, correct?

A Correct.

Q So for about 11 months?

A Right. It acquired a bunch of existing assets from the El Paso Corporation, as well as several El Paso employees to try and capture the expertise that El Paso had.

Q You have never been involved in resource planning for a regulated utility that has a native load and an obligation to serve, correct?

A Correct.

Q So you are not an expert in resource planning for a regulated utility, correct?

A Correct.

Q And you have never been involved in transmission planning for a regulated utility that has a native load and an obligation to serve, correct?

A Correct.

Q So you are not an expert in transmission planning for a regulated utility, correct?

A Correct.

Q You have never had a job that required you to be an expert on FERC orders regarding transmission access, correct?

A Correct.

Q So you are not an expert regarding FERC orders on transmission access, correct?

A Correct.

Q You first learned about the purchased power agreements, proposed purchased power agreements between FPL and

Southern Company and this PSC docket when your boss forwarded you a fax from Joe McGlothlin, FIPUG's counsel, correct?

A Correct.

Q Northern Star isn't a member of FIPUG, is it?

A It is not.

Q You didn't talk to anyone at FIPUG before you filed testimony on their behalf in this docket, did you?

A No, I did not.

Q You couldn't name any member of FIPUG, could you?

A I could not.

Q You are not charging FIPUG a professional fee for your services, are you?

A I am not.

Q So FIPUG is not compensating you for your participation in this docket?

A Correct.

Q You are participating free of charge?

A Correct.

MS. SMITH: That's all.

CHAIRMAN BAEZ: Staff?

MS. VINING: Staff has no questions.

CHAIRMAN BAEZ: Mr. McGlothlin?

MR. McGLOTHLIN: No redirect.

CHAIRMAN BAEZ: Thank you, Mr. Knauth.

Oh, I'm sorry. Commissioners, do you have any

questions of this witness?

Thank you, Mr. Knauth.

I'm showing Exhibit 71, the errata sheet, Mr. McGlothlin?

MR. McGLOTHLIN: Thank you, Mr. Chairman. I move 71.

CHAIRMAN BAEZ: Without objection.

(Exhibit 71 admitted into evidence.)

MS. KAUFMAN: Mr. Chairman, FIPUG would call Michael Vogt.

Whereupon,

MICHAEL F. VOGT

was called as a witness on behalf of FIPUG, and having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. KAUFMAN:

Q You have been sworn, have you not, Mr. Vogt?

A Yes, I have.

Q Would you state your name and address for the record, please?

A My name is Michael Vogt. My address is 400 Chesterfield Center, Suite 110, St. Louis, Missouri 63017.

Q On whose behalf are you appearing in this case, Mr. Vogt?

A FIPUG.

Q Did you cause to be filed in this docket 13 pages of

testimony on October 4th?

A Yes, ma'am.

Q And was it prepared under your direction and supervision?

A Yes, ma'am.

MS. KAUFMAN: Mr. Chairman, I have distributed an errata sheet, which we would ask to be marked. I think it is 72.

CHAIRMAN BAEZ: Show the deletions from Vogt testimony marked as Exhibit 72.

(Exhibit 72 marked for identification.)

BY MS. KAUFMAN:

Q Mr. Vogt, do these deletions and changes to your testimony relate to the fact that the Progress project was eliminated from consideration here?

A Yes, ma'am, they do.

Q And with the changes in your errata sheet, is your testimony true and correct?

A Yes, it is.

MS. KAUFMAN: Mr. Chairman, I would ask that Mr. Vogt's prefiled testimony and his errata be inserted into the record as though read.

CHAIRMAN BAEZ: Without objection, show the direct testimony of Witness Vogt entered into the record as though read, and also for the record show that Exhibit 72 contains

deletions from that testimony. And at this point, I guess, without objection we can move the errata sheet in, as well. We will just get that unless you all have any objection. That way we don't forget, or at least the Chairman doesn't forget.

Your witness.

(Exhibit 72 admitted into the record.)

INTERVENOR TESTIMONY OF

MICHAEL F. VOGT

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael F. Vogt. My business address is 400 Chesterfield Center, Suite 110, Chesterfield, Missouri 63017.

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

A. I am employed by LS Power Development, LLC, the general partner of LS Power Associates, L.P. (LS Power Associates). My title is Project Manager.

Q. Briefly describe your educational experience and background?

A. I have 12 years experience in the electric power industry. I have a Bachelors of Science in Mechanical Engineering, from the University of Missouri – Columbia and am a registered professional engineer in the State of Missouri. From 1992 to 1997, I was employed by Black & Veatch as a mechanical engineer involved in the design, start-up, and testing of power generation facilities. Since 1997, I have been employed by LS Power in various positions. At LS Power, I have been involved in the site selection, community relations, permitting, development, marketing, financing and management of independent power projects.

Q. Briefly describe LS Power Associates.

LS Power Associates is an independent power producer that develops, owns, operates and manages large-scale power generation projects in the United States. Since 1990, LS Power Associates and its predecessor companies (LS

Power) have successfully developed nine green-field domestic power generation projects totaling in excess of 5,700 megawatts (MW) of electrical output and representing a capital investment of approximately $3 billion.

Q. Is LS Power involved in wholesale power activities in the southeastern United States?

A. Yes. LS Power has been active in developing, owning and managing power generation projects in the southeastern United States for the majority of its history. More recently, we have been focused on the development of a coal-fired power generating facility in Early County, Georgia. We expect to complete permitting of this project in the second half of 2005 and have targeted an in-service date in late 2009 or 2010. The activities to date have included: securing real estate for the project site, extensive public relations work at the local and state level, preparation and filing of various environmental permits, and marketing power output from the facility.

SUMMARY

Q. On whose behalf are you testifying in this docket?

A. I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG is an ad hoc group of large industrial consumers that participates annually in the fuel adjustment proceedings with the aim of ensuring that the costs charged to consumers through the various recovery clauses, including the fuel adjustment clause, are just and reasonable. It is my understanding that the FIPUG group actively supports a competitive wholesale market for power. I

further understand that FIPUG also strongly supports the Florida Public Service Commission's Mission Statement, which appears on its website, and states:

> Customers are served best by markets that facilitate the efficient provision of safe and reliable utility services at fair prices. The mission of the Florida Public Service Commission is to promote the development of competitive markets – as directed by state and federal law – by removing regulatory barriers to competition, and by emphasizing incentive-based approaches....

In keeping with these stated policies, and because under the Commission's guaranteed cost recovery mechanisms consumers bear the full risk of purchased power contracts, FIPUG seeks affirmative proof that the proposed UPS purchase power agreements (UPS PPAs) I discuss below are the most efficient and economical choice for retail ratepayers. FIPUG companies are captive customers of Florida Power & Light (FPL) and Progress Energy Florida (Progress Energy). For this reason, they feel entitled to reassurance that these utilities have met their fiduciary responsibility to customers to fully survey and analyze all options available to meet the capacity needs of their retail customers at the possible lowest cost and that the contract provisions provide sufficient identification of the cost components so that they can be fairly allocated between customer classes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend a more deliberate and careful approach for evaluating long-term purchase agreements. The UPS PPAs for

which FPL and Progress Energy seek multiyear preapproval comprise large, long-term power purchase commitments. Before the Commission approves such commitments, it should be fully satisfied by competent substantial evidence that all options to fill the utilities' capacity needs have been thoroughly and appropriately analyzed in a manner to ensure that the interests of the Florida ratepayers have been adequately represented. Privately negotiated bilateral contracts aren't necessarily bad, but they do lack the imprimatur that comes with open market transactions, thereby making it all the more important to have adequate time for evaluation of them. As the Commission noted in last year's fuel adjustment proceeding, the truncated time frame of the fuel adjustment does not lend itself to the type of analysis needed for significant and complex issues. Thus, the question of the appropriateness of the UPS PPAs at issue should be considered in a separate docket where all parties have sufficient time to conduct discovery and thoroughly analyze the transactions and alternatives to the transactions.

Q. What documents other than the Commission Mission Statement mentioned above did you review in preparing your testimony?

A. In preparing my testimony, I have reviewed the following documents:

a. The testimony of Tom Hartman of FPL and Exhibits TLH-1 through TLH-6, dated September 9, 2004, filed in this docket; and

b. The direct testimony of Samuel S. Waters of Progress Energy, dated September 9, 2004, filed in this docket.

Q. Based on your review of these documents, what is your understanding of the UPS PPAs for which approval is sought?

A. Based on my review of the previously referenced documents and witness testimony, it appears that:

a. FPL has negotiated three PPAs with subsidiaries of the Southern Company that will begin on June 1, 2010 and extend until December 31, 2015. The three contracts represent 955 MW of generating capacity. Specifically: i) an approximately 165 MW (19.57% of unit capacity) purchase contract with Georgia Power Company and Gulf Power Company from the Robert W. Scherer Unit 3 coal generating station, ii) an up to 600 MW (100% of unit capacity) purchase contract with Southern Power Company from the Harris Unit 1 combined cycle facility, and iii) an approximately 190 MW (35.1% of unit capacity) purchase contract with Southern Power Company from the Franklin Unit 1 combined cycle facility.

b. Progress Energy has negotiated a Letter of Intent to Purchase Capacity and Energy from the Southern Company. Specifically, Progress Energy expects to negotiate definitive agreements with: i) Georgia Power Company and Gulf Power Company for the purchase of 8.77% of the demonstrated capacity of the Scherer 3 coal fired steam turbine estimated to be 74 MW and ii) Southern Power Company for the purchase of approximately 64.4% of the entire output (estimated to be 351 MW) of capacity from the Franklin Unit 1 combined cycle facility, located in

Smiths, Alabama. Both of these agreements are to begin on June 1, 2010 and end on May 31, 2015.

c. Testimony provided by both witnesses indicate that they believe it is important for the Commission to approve these contracts because:

i. They have a coal component;

ii. They provide access to existing transmission in the Southern region, which provides increased access to other generating resources and enhances system supply reliability; and

iii. The purchases allow FPL and Progress Energy to defer additional generating capacity in 2010.

Q. In your opinion, does sufficient time exist for the Commission and affected parties to adequately review and evaluate the UPS PPAs described above in this docket?

A. No. As the Commission has previously recognized, the regulatory nature of the fuel adjustment proceeding is such that it has a narrow focus and an accelerated review schedule. The fast track of the fuel docket left FIPUG with an unrealistically small window of opportunity to review, analyze and conduct discovery on the utility's testimony. The procedural order[1] in this docket provides for a shortened 20-day discovery response time. If FIPUG had analyzed the testimony and formulated comprehensive discovery so as to have served it the very day after the testimony was filed (September 10th), and if all the answers had been complete with no objections lodged, it would have received such responses on September 30th – one business day before Intervenor testimony is

[1] Order No. PSC-04-0160-PCO-EI at 1 (February 17, 2004).

due. This is not sufficient time to prepare, serve, receive and analyze even one full round of discovery prior to the testimony due date, let alone conduct follow-up discovery or depositions. In sum, the time allowed to conduct discovery in this docket was not sufficient to conduct meaningful discovery and prepare testimony based on that discovery.

Q. Are there further complications to a truncated review of these PPAs?

A. Yes. Review is further complicated, and thus made more time consuming, by the number and types of purchase contracts for which the utilities seek approval. FPL is requesting approval of three different UPS PPAs, from three separate power generation facilities, with two different fuel types, and two different counter parties. Progress Energy similarly is requesting approval of two different UPS PPAs, two different power generation facilities, two fuels and two different counter parties. In addition, the contracts need to be thoroughly examined to give the public the comfort of knowing there are no contract provisions or affiliate relations that pose a risk of harm to consumers.

Though the provisions of the "bid rule" do not apply to the UPS PPAs, such agreements present many of the same policy issues as the addition of generating capacity. This is especially true considering that the UPS PPAs at issue here seek to defer the addition of generating capacity in 2010. In the spirit of the bid rule, it is important that all options be explored, as they certainly would be if additional generating capacity were being built, to ensure that the price of these agreements is fair, just and reasonable for the ratepayers.

Q. Must the resources contemplated by the UPS PPAs be procured now?

A. It would not appear that the resources contemplated by the UPS PPAs need to be procured now. The current UPS contracts do not expire until June 1, 2010, nearly six years from now. Neither FPL nor Progress Energy have provided an adequate explanation as to why other competitive options were not investigated. There certainly seems to be enough time to do this and still meet the required date of June 1, 2010. The primary two components of generating resources being procured under these UPS PPAs are natural gas combined cycle and coal generating capacity. Given the rather extensive gas-fired generating resources located in the southeastern region of the United States and the fact that a new coal unit would still have time to be constructed to meet an in-service date of June 1, 2010, it would seem to be in the best interest of the ratepayers of the state of Florida to explore all alternatives for meeting the need contemplated by the UPS PPAs to ensure that the best choice is made. Further, the testimony of the witnesses did not seem to indicate that Southern Company would be unwilling to negotiate similar type contracts with FPL and Progress Energy at a date nearer to expiration of the UPS contracts.

Q. Transmission rights appear to be a factor that may be driving these PPAs. Do FPL and Progress Energy have to enter into the UPS PPAs with Southern Company to be entitled to "roll over" their existing transmission rights on the Southern Company side of the Southern/Florida interface?

A. Based on the testimony I reviewed, it is unclear. The testimony of Progress Energy witness Mr. Waters indicates that access to transmission rights may be part of the UPS PPAs. Mr. Waters refers to "Access to the transmission facilities

provided by the agreement..." and also notes that "...[t]he agreement will maintain a transmission path to the Southern system..." (Waters Direct Testimony at 7). However, in Mr. Waters' Exhibit ____(SSW-2), the terms of the Letter of Intent with Southern Company indicate that obtaining transmission service on the Southern side of the interface is the responsibility of Progress Energy. From my review of the testimony, there were no additional clarifying statements regarding the transmission rights; thus these statements seem to contradict each other and make it unclear what transmission rights Progress Energy believes it has on the Southern system.

In reviewing Mr. Hartman's testimony, he indicates that FPL will be able to "roll over" its transmission rights to other sources of energy and capacity, provided certain conditions are met. These include demonstrating that "...the changed delivery points (from the existing UPS Agreement to the new contracts) do not cause substantial changes in the transmission provider's system flows..." (Hartman Direct Testimony at 8). Mr. Hartman goes on in his testimony to explain why he believes FPL will be able to meet this requirement with the new contracts. Although Mr. Hartman's testimony in several instances indicates a link between the UPS PPAs and transmission rights, nothing in Mr. Hartman's testimony specifically states that the "roll over" of these transmission rights is contingent on signing the UPS PPAs with Southern Company. This is just one of several important issues which the parties and the Commission need to analyze. This issue is important because if it turns out that the transmission rights may be

"rolled over" without execution of these UPS PPAs, then a significant amount of benefits attributed to execution of the UPS PPAs no longer exists.

Q. Do you agree with the FPL and Progress Energy witnesses as to the importance of retaining firm transmission rights on the Southern side of the interface?

A. Yes. From everything that we have seen in the wholesale power market in the southeastern United States, access to transmission capacity is vitally important to utilities to be able to secure competitively priced wholesale power. It would seem to go without saying that those who control the transmission capacity on the Southern side of the interface control the flow of wholesale power into Florida — and currently I believe opportunities for competitive power do exist on the Southern side of the interface. This is especially important with regard to moving power into peninsular Florida. Because there is a limited amount of interface transfer capability and all existing transmission capacity is subscribed on a long-term firm basis, it would be important for FPL and Progress Energy and their ratepayers to "roll over" these rights, and thus maintain the transmission rights that the witnesses' testimony appears to indicate they have paid for as a part of the existing UPS contracts. However, as I stated earlier it is not clear that the utilities must enter into these UPS PPAs to retain their firm transmission rights.

Q. Do you believe there is enough time in this docket for affected parties and the Commission to adequately evaluate the reasonableness of the UPS PPAs?

A. No I do not. Both witnesses offer some analytical, as well as subjective, methods to aid in demonstrating the reasonableness of the UPS contracts. Each of these methods, no doubt, has substantial assumptions that need to be assessed for appropriateness. For example, Mr. Hartman's testimony refers to a review of available generation resources in the southeast. A significant amount of time would be required to verify the accuracy of the list as well as the assumptions associated with it, including the reasonableness of eliminating the majority of the generating resources because of transmission constraints that may or may not still be in effect in June of 2010.

Q. Do you believe a coal purchase alternative could be available by June 1, 2010 in lieu of the purchase from Southern Company?

A. Yes. Based on discussions we have had with engineering and construction firms, a new coal fired generation facility can be constructed in approximately 42 months. Further, based on our permitting experience, we believe that it is possible for a new coal-fired generating facility to be permitted in approximately 18 months. Based on these dates, neither FPL nor Progress Energy, nor a potential entity that they may contract with, would need to begin permitting a new coal facility until mid-2005 and would not need to begin construction of a new facility until nearly the end of 2006.

Additionally, as previously mentioned, LS Power has completed a substantial amount of permitting on a coal-fired generating facility in southwest Georgia. This facility is expected to be fully permitted in the second half of 2005.

RECOMMENDED ACTION

Q. What action do you recommend the Commission take regarding these contracts?

A. I recommend that the Commission allow more time for the evaluation of the merits of the UPS PPAs by opening a separate docket to consider them. Because of the relatively truncated nature of this particular docket, it is impossible to have adequate time for affected parties to prepare discovery requests and provide expert analysis. When transactions of the magnitude of the UPS PPAs are at issue, such critical analysis is essential.

The Commission addressed the problems raised by the analysis of complex issues in a truncated proceeding in last year's fuel docket. Chairman Jaber stated:

> It seems to me that this administrative process has had its benefits in terms of efficiencies, but some of these issues aren't as routine as they've been in the past. So if we could find a way to keep the issues that are routine in this very expedited process, great, but I don't like the feeling of being rushed, not having a lot of evidence, second guessing.[2]

Commissioner Deason added:

> Let me say that I agree with what you're saying. And it's difficult on the parties, it's difficult on the staff, it's difficult on the Commissioners to have these very intense, meaningful debates with evidence and cross-examination on these significant policy issues within the confines of this once a year November hearing where we're trying to get fuel factors finalized to be effective January.
>
> And I would just ask Public Counsel, FIPUG, all of the participants, if there's a better way of doing it, let's think about it. Maybe the way we're doing it is best, but it just seems to me that when we start talking about these very significant policy issues, it

[2] Hearing Transcript, Docket 030001-EI at 1276.

> would be better to have a little bit more -- the luxury of having a little bit more time as opposed to being pressed against this deadline and having to make bench decisions.
>
> I'm not critical of what we've just done. Just like the Chair, I think these issues have been very thoroughly litigated, that the parties did a superb job in presenting their cases, but we did it in a very compressed time frame, and we did not have the luxury of having briefs filed if we thought that would be helpful. We didn't have the luxury of staff analyzing all of that and coming forward with a written recommendation. While I applaud staff for your oral recommendation, I just think that some of these issues would be better addressed in a more traditional atmosphere, if possible.[3]

The same reasoning applies to the complex, long term, multi-million dollar contracts at issue here.

Q. Does this conclude your testimony?

A. Yes.

[3] Hearing Transcript, Docket No. 040001-EI. at 1277-78

BY MS. KAUFMAN:

Q You don't have any exhibits, Mr. Vogt, do you?

A No, I do not.

Q Have you prepared a summary of your testimony?

A Yes, I have.

Q If you would please give that.

A Good afternoon, Commissioners. My name is Michael Vogt. I'm appearing before you today on behalf of the Florida Industrial Power Users Group. I am employed by LS Power Development, LLC. I am a registered professional engineer in the State of Missouri, and I have twelve years experience in the power generation industry.

During my twelve years in the power generation industry, I have gained substantial expertise in the areas of power plant design, start up, testing, site selection, community relations, permitting and development of independent power projects.

LS Power Development, LLC and its predecessor companies have developed projects totalling 5,700 megawatts of generating capacity and representing a capital investment of approximately $3 billion. And as probably most pertinent to your consideration today, LS Power has under development a 1,600 megawatt coal-fired generating project in Early County, Georgia that would be in a similar transmission path as the FPL PPAs being considered in this docket.

The purpose of my testimony is three-fold. First, to support the position espoused by FIPUG and its members that a robust and competitive market for supplying wholesale power is in the best interest of the ratepayers of Florida. Second, that the best way to determine if the PPAs being brought forward by FPL for approval are truly the best alternative for ratepayers is to ensure that the market has been thoroughly tested, and I believe FPL has failed to do that. And, finally, to suggest that the Commission take adequate time to thoroughly analyze these very large multi-million dollar PPAs.

I have reviewed the testimony and exhibits of FPL Witness Hartman. It appears to me that FPL acted prematurely in securing capacity to replace the UPS contracts that are expiring nearly six years from now, and did so with only cursory analysis and evaluation of potential alternatives to the PPAs in question.

I understand that the main benefits FPL suggests are part of these contracts are, number one, access to coal-based capacity; number two, access to the existing transmission path on the Southern side of the interface; and, number three, allowing FPL to defer constructing additional generating capacity in 2010. More competitive alternatives may very well exist to obtain or construct coal-based capacity, especially since the PPAs only provide 165 megawatts of coal. I believe this may be true given the time frame before the UPS contracts

expire, and that executing the PPAs in question do not appear to be required for FPL to retain the transmission rights on the Southern side of the interface.

In fact, as I mentioned, LS Power Development, LLC, is currently developing a large scale coal-fired generating facility in southwest Georgia that could supply coal-based capacity for all 930 megawatts of FPL's needs to replace the expiring UPS contracts, which are also 100 percent coal-based.

We have completed a substantial amount of development work on this project, and expect to have it fully permitted by the second half of 2005, and in commercial operation by June 1, 2010. This and all other alternatives need to be analyzed before the Commission can be in a position to say that FPL's proposal is in the best interest of its ratepayers.

That concludes my summary.

CHAIRMAN BAEZ: Thank you, Mr. Vogt. Mr. Vogt is available for cross-examination.

Ms. Christensen.

MS. CHRISTENSEN: No questions.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: Just a couple, brief questions.

CROSS EXAMINATION

BY MR. MOYLE:

Q How many coal-fired projects does LS Power have in development in the southeast?

A In the southeast we have two.

MR. BUTLER: Excuse me, I would object to this as friendly cross. I don't see how Mr. Moyle's interests could possibly be adverse to either FIPUG's or Mr. Vogt's in this proceeding.

CHAIRMAN BAEZ: You're right, Mr. Butler. I think friendly cross is a fair -- but that is practice, I'm going to let him go on and ask the questions.

BY MR. MOYLE:

Q How many coal-fired projects in the southeast?

A Two, sir.

Q And what are they?

A They are the Longleaf facility that I mentioned in southwest Georgia, and our Plum Point generating facility in Osceola, Arkansas.

Q And what are the in-service dates of those?

A The Longleaf facility would be by June 1st, 2010 or earlier, and the Plum Point facility would be 2009.

Q Could you explain how a coal-fired unit can still be developed and constructed in time to meet an in-service date of June 1, 2010?

A In some specific location, or here in Florida?

Q Well, the plants you identified.

MR. BUTLER: I'm to object again, Chairman Baez. He is trying to build a record with evidence that has not been

prefiled, doing this clearly to support interests that are allied with those of the witness and his sponsor. I just think it is completely inappropriate.

CHAIRMAN BAEZ: Now that part I think we are going to need to explain. Mr. Moyle, can you point to where in his testimony you are taking your questions?

MR. MOYLE: Page 8, Line 9. Also Page 11, Line 10.

CHAIRMAN BAEZ: Page 8?

MR. MOYLE: Yes. My notes reflect Page 8, Line 9, also Page 11, Line 10.

CHAIRMAN BAEZ: Can you explain to me where the reference to the existing projects of LS Power are?

MR. MOYLE: That may not be the right cite. Let me just follow up with --

CHAIRMAN BAEZ: Here is the instruction, Mr. Moyle, this is as I have already recognized, friendly cross, and that is done as a courtesy to the parties. And, Mr. Butler, I overruled your objection because that has always been done as a courtesy to the parties.

However, there are some strings attached that. And this is not going to become a -- I don't know the word -- infomercial comes to mind, okay? So be very, very careful to stay within the scope of the direct testimony that has been filed. That is my admonition.

MR. MOYLE: Okay.

BY MR. MOYLE:

Q Mr. Vogt, you identified these two plants. Do you know if either of these plants would be available in time to serve an FPL need in 2010, June?

A Yes, I believe both of them could be.

Q Were you ever contacted by FPL about providing energy and capacity to them?

A No, we were not.

MR. MOYLE: I have nothing further.

CHAIRMAN BAEZ: Ms. Smith or Mr. Butler?

MR. BUTLER: Ms. Smith.

MS. SMITH: Natalie Smith for FPL.

CROSS EXAMINATION

BY MS. SMITH:

Q Good afternoon, Mr. Vogt.

A Good afternoon.

Q You are project manager for LS Power Development, correct?

A Yes, ma'am.

Q LS Power is an independent power producer, correct?

A Yes.

Q Have you ever contacted FPL regarding providing power to FPL?

A Not me personally, but LS Power has

Q And what did FPL tell LS Power?

A I believe that they were negotiating contracts and that they were not interested in receiving a proposal from us at the time.

Q Is it correct that FPL asked LS Power for information and LS Power has never responded to FPL with that information?

A That I do not know. I did not recall having been asked to provide information and not having provided it.

Q You have never been involved in resource planning for a regulated utility that has a native load and an obligation to serve, correct?

A No, I have not.

Q You have never been involved in transmission planning for a regulated utility that has a native load and an obligation to serve, correct?

A No, I have not.

Q You don't consider yourself an expert in transmission planning, correct?

A No, I do not.

Q You don't consider yourself an expert in resource planning for a regulated utility, correct?

A No, I do not.

Q You have never had a job that required you to be an expert regarding FERC orders on transmission access, have you?

A No, I have not.

Q You don't consider yourself an expert regarding FERC

orders on transmission access, correct?

A No, I do not.

Q You first learned about the proposed purchased power agreements between FPL and Southern Company from a regulatory news service, correct?

A Yes.

Q And LS Power contacted FIPUG's counsel after learning about the FPL/Southern Company purchased power agreements, correct?

A An attorney within our firm contacted Ms. Kaufman's firm.

Q An attorney within LS Power?

A Yes.

Q And you first learned about FIPUG when you contacted FIPUG's counsel, correct?

A Yes.

Q You didn't talk to any members of FIPUG before you filed testimony on their behalf in this docket, did you?

A I did not speak directly to any FIPUG members before filing the testimony, no.

Q You don't know any members of FIPUG who are FPL customers, do you?

A At the time of my deposition, I did not. Since then I have looked and know a few; Publix, I think Mosaic. That's all.

Q But at the time of your deposition, you didn't?

A At the time of my deposition I did not, that is correct.

Q FIPUG isn't compensating you for your participation in this docket, are they?

A No, ma'am.

Q So you are charging FIPUG no fees for your participation in this docket?

A No, I'm not.

MS. SMITH: Thank you. I have no further questions

CHAIRMAN BAEZ: Staff.

MS. CHRISTENSEN: Staff has no questions.

CHAIRMAN BAEZ: Commissioners, any questions?

MS. KAUFMAN: I just have two short redirect, Mr. Chairman.

CHAIRMAN BAEZ: Go ahead, Ms. Kaufman.

REDIRECT EXAMINATION

BY MS. KAUFMAN:

Q Mr. Vogt, Ms. Smith asked you if LS Power had been contacted by FPL and asked for information and then LS Power had not provided it, and you said you did not know. Would it be likely that LS Power would not respond to an inquiry from Florida Power and Light?

MS. SMITH: Objection, leading.

MS. KAUFMAN: I can rephrase the question.

BY MS. KAUFMAN:

Q What do you think LS Power would have done if it had received an inquiry from Florida Power and Light?

A It would depend on how the inquiry was made.

Q Ms. Smith also asked you if you had talked to any FIPUG members about your testimony. Do you recall that?

A Yes.

Q Do you know whether or not any FIPUG members reviewed your testimony?

MS. SMITH: Objection, leading.

BY MS. KAUFMAN:

Q Did any FIPUG members review your testimony?

A Ms. Kaufman, you informed me that it was reviewed and approved by somebody at FIPUG, that's all I know.

MS. KAUFMAN: Thank you. That's all I have.

CHAIRMAN BAEZ: Thank you, Ms. Kaufman. I'm showing Exhibit 72.

MS. KAUFMAN: Yes, the errata sheet. I think we already moved it.

CHAIRMAN BAEZ: And I think we already did that. Thank you, Mr. Vogt.

Let's take a ten-minute break. And by my count our last witness is Mr. Hartman on rebuttal.

MR. BUTLER: Yes, sir.

CHAIRMAN BAEZ: Okay.

(Recess.)

CHAIRMAN BAEZ: We will go back on the record.

Mr. Litchfield.

MR. LITCHFIELD: Yes, sir, Mr. Chairman. We are calling Mr. Hartman to the stand in connection with his rebuttal testimony.

Whereupon,

THOMAS L. HARTMAN

was called as a rebuttal witness on behalf of Florida Power and Light, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LITCHFIELD:

Q Mr. Hartman, would you please state your name and business address?

A My name is Thomas L. Hartman. My business address is 700 Universe Boulevard, Juno Beach, Florida.

Q And that hasn't changed since yesterday?

A No, it has not.

Q Have you prepared and caused to be filed 17 pages of prefiled rebuttal testimony in this proceeding?

A Yes, I have.

Q Do you have any changes or revisions to your prefiled rebuttal testimony?

A No, I do not.

Q If I were to ask you the same questions today

reflected in your rebuttal testimony, would your answers be the same?

A Yes, they would be.

MR. LITCHFIELD: Mr. Chairman, I would ask that Mr. Hartman's prefiled rebuttal testimony be inserted into the record as though read.

MR. McGLOTHLIN: I have a brief objection to one sentence in that testimony.

CHAIRMAN BAEZ: Would you point it out, sir?

MR. McGLOTHLIN: Yes, sir. It is on Page 10, Lines 20 through 22. And for purposes of my objection, I need to ask the witness a couple of brief questions on voir dire.

MR. LITCHFIELD: Well, again, Mr. Chairman, this is on less than short notice, and I think -- well, we are amenable to whatever you want to do, Mr. Chairman, at this late point.

CHAIRMAN BAEZ: Be careful what you wish for. I'll tell you what, Mr. Litchfield, I want to let Mr. McGlothlin ask his couple of questions and see, so that I can have some time and read this statement and see exactly what the problem is.

VOIR DIRE EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Hartman, at Page 10, Lines 20 through 22, you had this statement, "Mr. Knauth also fails to mention transmission constraints that would preclude getting the power from that unit to our customers cost-effectively."

Is it true, sir, that when I asked you about that statement during your deposition you could not identify the location of the transmission constraint or the nature of it?

A That is true, sir, but I don't have any --

Q Excuse me, I think that is a yes or no question.

MR. LITCHFIELD: Well, I object. I think the witness may clarify.

CHAIRMAN BAEZ: Hold on. You are going to let him elaborate, right? Let's don't box him into a yes or no answers. Answer yes or no, Mr. Hartman, and clarify your answer if you feel the need to.

A (Continuing) Yes, I did not say that I did not know and do not know the exact nature of the transmission constraint. It isn't necessary for me to know so. What I do know is we have looked multiple times at purchasing power from the Vandolah unit. We have had transmission studies done as far as the upgrades that are necessary. The economics of the upgrades that are necessary have prevented us from buying power from the unit because it makes it way too expensive to upgrade the transmission system.

Q And, you also said that you were not the source of the statement, but that it was provided to you, is that correct?

A That's correct.

Q And at the time we spoke during your deposition you

could not identify the person who provided the statement to you?

A That is correct.

MR. McGLOTHLIN: The nature of my objection is this, Mr. Chairman. To be admissible, the testimony needs to be relevant and it needs to be competent. And while Mr. Hartman is obviously a competent witness in many respects, he has acknowledged that he is not the source of this, nor can he tell me who was the source, and at the time I questioned him he could not elaborate on the nature, location, or severity of the transmission constraint, thereby frustrating my attempt to prepare for the hearing. So, this is not an instance of hearsay, it has to do with the very fundamental proposition that a witness should be testifying on something of which he has personal knowledge, and that is not the case here.

MR. LITCHFIELD: May I respond, Mr. Chairman?

CHAIRMAN BAEZ: Go ahead, Mr. Litchfield.

MR. LITCHFIELD: As an expert, and our witness is an expert, he is entitled to rely on things that ordinarily experts would rely upon. And I don't think that Mr. McGlothlin has established that Mr. Hartman has inappropriately relied upon evidence in connection with sponsoring his testimony, or in particular this statement. And I think it is fair to ask Mr. Hartman a question or two that would help elaborate that point.

CHAIRMAN BAEZ: Now you guys have really stumped me. I mean, I don't know, I don't know anything, and Mr. Melson left, but I'm not sure that I know anything that allows you to rehabilitate a witness on voir dire. Do you know something that allows you to do that, anyone? It's okay, I have already admitted ignorance. I mean, anything you throw up there I may have to take.

Mr. Melson, do you want to help me out here?

MR. MELSON: I think on voir dire either side is able to ask a few questions to give you a basis to make a ruling. I think it is permitted. At least I have done it in the past.

CHAIRMAN BAEZ: Very well.

Go ahead, Mr. Litchfield.

Listen, I will be honest with you, it sounds only fair, but since we are into esoteric legal issues here, go ahead, Mr. Litchfield.

BY MR. LITCHFIELD:

Q Mr. Hartman, you have been focused on the sentences that Mr. McGlothlin has been discussing with you?

A Yes, I have been.

Q Would you please explain the basis for those statements in your testimony?

A There is a number of people that analyze power plants and power purchase agreements in our company. Some of them are in our energy marketing and trading group, some of them are in

our resource planning. Both of them have taken a look at the Vandolah unit and possibility of getting power from it. What I relied upon in preparing this testimony, and at the time of my deposition did not recall the name of the people that had provided me the information, but it comes from both sources. It comes from an individual by the name of Barry Anderson, who is in our trading group, and our trading group looks at short-term purchases from Vandolah. It comes from Steve Scroggs, who is in our resource assessment and planning, who looks at long-term power purchase agreements.

Both of them at independent times had analyzed the capability of getting power to our customers from the Vandolah unit, both of them required transmission studies and assessment of transmission necessary to get it as we typically do. Both of them came back with an answer from transmission planning as far as upgrade costs to cost-effectively get the power to our customers, and in both cases it made it not cost-effective. So I was relying upon two different departments who had independently done an analysis on the Vandolah unit using their expertise and the expertise of our transmission system planning department.

Q And these individuals undertake these types of analyses in connection with their job responsibilities at Florida Power and Light?

A All the time.

Q And these are the people that you would typically rely upon for this type of assessment?

A Absolutely.

MR. LITCHFIELD: I have nothing further.

CHAIRMAN BAEZ: Mr. McGlothlin, I'm going to overrule your objection, the language stays. Do you have any others?

MR. McGLOTHLIN: No, sir.

CHAIRMAN BAEZ: Thank you. Where were we? Without further objection, we will enter the rebuttal testimony of Mr. Hartman into the record as though read.

BY MR. LITCHFIELD:

Q Do you have exhibits, Mr. Hartman, in connection with your rebuttal testimony that you are sponsoring?

A Yes, I do.

Q And those would be TLH --

A 7 and 8, I believe.

Q -- 7 and 8.

MR. LITCHFIELD: And they have been prenumbered, Mr. Chairman, as Exhibits 19 and 20.

CHAIRMAN BAEZ: That is what I am showing, 19 and 20.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TOM HARTMAN

DOCKET NO. 040001-EI

October 18, 2004

Q. Please state your name and business address.

A. My name is Thomas L. Hartman. My business address is 700 Universe Blvd., Juno Beach, FL 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Director of Business Management for Resource Assessment and Planning.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed direct testimony in this docket on September 9, 2004.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the testimonies of merchant witnesses Dismukes, Knauth and Vogt, who erroneously allege that: (1) there is no need for the Florida Public Service Commission (Commission) to approve, on the timetable presented by Florida Power & Light (FPL), the Power Purchase Agreements (PPAs) between FPL and affiliates of the Southern Company,

dated August 11, 2004; (2) FPL did not consider the available alternatives before entering into the PPAs; (3) consistent with the spirit, if not the letter of the Commission's bid rule, FPL should have issued a request for proposal (RFP) to compare all market alternatives to the PPAs; (4) an FPL self-build option is superior to the PPAs; and (5) FPL could obtain all the benefits associated with the PPAs under other market alternatives.

My rebuttal testimony shows that the merchant witnesses are wrong on each of those points. Specifically, I will explain that, contrary to their allegations: (1) it is critical that the Commission approve FPL's PPAs promptly in order to ensure that the benefits of the PPAs are preserved for FPL's customers; (2) FPL considered all relevant alternatives that could provide similar benefits to FPL's customers and found that the PPAs were clearly superior; (3) the RFP process contemplated by the Commission's bid rule does not apply to the PPAs and would not serve the best interests of FPL's customers in this case; (4) when all of the benefits of the PPAs are considered, they are a superior choice to accelerating a self-build option into the 2010 time frame; and (5) FPL has no assurance that it could obtain all the benefits associated with the PPAs under any other market alternative.

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

A. Yes. It consists of the following documents:
Document TLH – 7 - Timeline for Firm Transmission Service
Document TLH – 8 – Southern Company Transmission Queue

NEED FOR PROMPT REVIEW AND APPROVAL OF PPAs

Q. Merchant witnesses Dismukes, Knauth and Vogt all suggest that immediate approval is not necessary. Do you agree?

A. No; I strongly disagree.

As I have previously testified, the PPAs give FPL only six months (180 days) from the date they were signed or until transmission rights are obtained, whichever is later, to secure Commission approval. The PPAs were signed on August 11, 2004, so this window of opportunity could close in early February 2004.

The merchant witnesses point to the possibility that more time might be available to secure Commission approval because Southern Company's decision on FPL's firm transmission "roll-over" request might not be made within this six-month period. But this is mere speculation, and FPL has no control over when that decision will be made. As noted in my Document TLH-7, it could take up to 240 days for FPL's firm transmission roll-over

request to be approved; however, FPL believes that approval may occur much earlier, perhaps before the end of 2004. This is because the facilities that provide capacity and energy under the PPAs were selected so as to maximize the likelihood that firm transmission rights would be granted without the need for extensive transmission studies by Southern Company. Therefore, we could obtain our firm transmission rights as early as 135 days from when we applied – that is, in less than six months. So, it is entirely possible that FPL will only have until early February to obtain final Commission approval. FPL would be foolish to gamble the opportunity to preserve the benefits of the PPAs for its customers on speculation that the transmission roll-over decision will take longer.

Mr. Dismukes maintains that there is no concrete or compelling evidence that the benefits of the PPAs will not exist in the future, so in spite of the limited window of opportunity for securing Commission approval, the Commission should take its time (Dismukes, page 34, line 5). Again, this inappropriately suggests that FPL should gamble the assured benefits of the PPAs on the hope of speculative and unpredictable benefits. For example, a key benefit of the PPAs is FPL's entitlement to firm coal-fired capacity. While Mr. Dismukes points to large quantities of merchant generating capacity in the SERC region, there is no firm coal-fired capacity in that area available to FPL in 2010 other than that provided under the PPAs. And FPL had to negotiate hard to secure the firm coal-fired capacity provided by the PPAs. Under the existing UPS

Agreement, FPL receives 210 MW from the Scherer 3 plant. Under the PPAs, this will be reduced to 165 MW. This reduction reflects the great demand for a limited amount of the coal-fired capacity in the region. Even this far in advance of the expiration of the UPS contract, Southern Company has already made a contractual commitment to someone else for part of the Scherer 3 capacity currently provided to FPL. If FPL has to forego the PPAs, there is no reason to believe that the coal component of the PPAs will not be committed to another party before FPL is able to negotiate any sort of alternative.

Another key benefit of the PPAs is their role in facilitating continuing access to firm transmission rights into the SERC region. There is a long list of firms that have applied for firm transmission studies to bring power and energy into Florida from SERC (Document TLH-8). If FPL were to simply request firm transmission, it would go to the end of this line. With our roll-over rights, however, we retain our existing transmission and do not have to get at the end of the queue. In my direct testimony (page 7 line 20) I state that FPL believes it has the right to roll over its transmission rights under the existing UPS Agreement. I further state that in order to successfully roll over the firm transmission rights using different delivery points (where generating plants connect to the transmission system) from those in the current UPS contract we expect that we will have to show that there are no substantial changes in system flows caused by the change in delivery points (page 8 line 2). We believe that with the delivery points we have selected under the PPAs there

will be no substantial changes in system flows and therefore our roll-over request will be granted for these PPAs. In contrast, there is no assurance that this same argument would be available to FPL if it does not enter into the PPAs.

Q. Did FPL try to obtain a longer period for the Commission to review and approve the PPAs?

A. Yes. FPL asked Southern Company to allow one year to obtain Commission approval for the PPAs. However, Southern Company was unwilling to keep its generating units "off the market" that long. Six months from the contract execution was the longest period of time to which they would agree for Commission review and approval.

Q. When did FPL first bring the PPAs to the attention of the parties in the fuel docket?

A. The PPAs were executed on August 11, 2004, and FPL brought them to the attention of all parties of the fuel docket and Staff at Staff's third periodic fuel clause status meeting, held on August 26, 2004. My direct testimony supporting approval of the PPAs was filed as part of FPL's projection filing on September 9, 2004, and FPL agreed with Staff to an additional meeting with all parties of the fuel docket and Staff on September 17, 2004 for questions about the filing, including my testimony. FPL has offered parties in

the docket additional opportunities for information and accelerated responses to discovery requests.

Q. Given that the existing UPS contract expires at the end of May 2010, why is FPL pursuing approval of the PPAs so far in advance of when the energy and capacity is needed?

A. FPL needs to act now for two reasons: (1) to ensure that it will have adequate resources to meet the needs of its customers in 2010, and (2) to preserve for its customers as many of the benefits of the expiring UPS contract as possible.

First, FPL must know soon whether it can proceed with the PPAs, because there is a considerable lead time for making alternative arrangements to meet its need for approximately 930 MW of capacity in 2010. Absent Commission approval of the PPAs, or absent roll-over of firm transmission rights, FPL might well have to pursue permitting and construction of new gas-fired units. As the Commission is aware, this is a complex process that could take as much as five years. Therefore, in order to allow sufficient time for FPL to pursue other alternatives if necessary, it is critical that we seek Commission approval of the PPAs at this time.

Second, FPL's timing was dictated to some extent by the timing of Southern Company's offer. Based on FPL's review of its alternatives, the only way to ensure that most of the benefits of the expiring UPS contract will be preserved

was to enter into the PPAs at the time when the offers were available to FPL, and then obtain the Commission's approval. If FPL were to forego the PPAs, it cannot be certain that any of those benefits would be preserved. Only through the PPAs can FPL bind Southern Company to provide the benefits to FPL's customers specified in the PPAs, such as firm coal-fired capacity. And only through the PPAs does FPL have a high level of confidence that the benefits not specifically guaranteed under the PPAs, such as firm transmission rights, will be obtained.

Q. Do the merchant witnesses have the best interests of FPL's customers in mind when they recommend against prompt review of the PPAs?

A. I do not believe that they do. Each of the merchant witnesses either works in or for the merchant generator industry. Commission approval of the PPAs would be against their interests regardless of whether the PPAs benefit FPL's customers.

FPL CONSIDERED ALL RELEVANT ALTERNATIVES TO THE PPAs

Q. Mr. Dismukes points out that there are a large number of potential providers in the SERC region that FPL did not consider. How can FPL be certain that it addressed all relevant alternatives to the PPAs?

A. The key question is which potential providers are really relevant. Mr. Dismukes states that there are 30,537 MW of non-peaking merchant facilities

in SERC (page 24 line 4), and then goes on to clarify that of that total only 7,548 MW is in the Southern Company subregion (page 24, line 12). If FPL were to contract for firm capacity and energy from generating units that are outside the Southern Company subregion, we believe that the new transmission system flows would be significantly different from those under the current UPS contract and that we could not roll over our firm transmission rights in that situation. FPL would not pursue such a speculative alternative. Therefore, 75% of the potential capacity initially identified by Mr. Dismukes is not relevant.

Of the remaining 7,548 MW discussed by Mr. Dismukes that are in the Southern Company region, Mr. Dismukes identifies five operating facilities, totaling 2,600 MW of capacity, as being in "Proximity to Contracted Units" (Exhibit DED-2). If we exclude the Harris (1,254 MW) and Franklin (1,185 MW) units which are part of FPL's PPAs, and we further exclude other Southern Company affiliated units which Southern Company has already said are not available to FPL, the relevant potential capacity is only 1,534 MW, none of which is coal fired.

Mr. Dismukes' list includes cogeneration plants. We elected to not include cogenerators in our screening, because they have minimum standards of efficiency and thermal energy use that must be maintained. Compliance with these requirements typically places restrictions on the ability of cogenerators

to dispatch freely. When the cogenerators are removed from Mr. Dismukes' list, all that remains are two Tenaska facilities in central Alabama. One of those facilities is under contract to Coral Energy and the other under contract to Williams Company, both through 2020.

Q. Why did FPL not consider Florida resources as an alternative to the PPAs?

A. Primarily because relying on in-state resources would result in FPL's losing its transmission rights into the SERC region. Those transmission rights provide valuable access to economy energy purchases from the SERC region and add geographical diversity to FPL's power supply.

I also would like to point out that the merchant witnesses do not identify any Florida resources that are realistically viable alternatives. For example, Mr. Knauth suggests that FPL could contract with the Vandolah facility. He acknowledges, however, that the output of that unit is contractually committed until 2012. While he suggests that perhaps Vandolah could terminate its commitment early, that is purely speculative and does not exactly inspire confidence that any commitment made to FPL would be respected. In short, the Vandolah unit is not realistically available to meet FPL's 2010 need. Mr. Knauth also fails to mention transmission constraints that would preclude getting the power from that unit to our customers cost-effectively.

Q. Why did you eliminate resources from consideration based upon current transmission constraints which may not exist in 2010?

A. FPL has no crystal ball that allows it to predict with confidence whether transmission constraints will be removed by 2010. While some existing congestion constraints may not exist in 2010, other new ones may arise. A decision must be made now, based on current knowledge.

Q. Why have you not considered plants in development or construction?

A. Again, projects in development must be considered speculative. As earlier discussed, we must know by the end of 2005 if we can count on the output of the facilities under contract to meet our needs.

I would like to discuss briefly the one project under construction that could be a potential candidate. That is the Hillabee project, owned by an affiliate of Calpine Corporation. This project is not coal-fired, so selecting it would lose the benefit of the coal-fired capacity afforded by the PPAs. Moreover, Calpine has announced that it is scaling back its capital spending programs to conserve capital. Given the history of changed completion dates and the stress the financial market is exerting on Calpine, there is no guarantee this project will be completed. For example, according to the transcripts of Calpine's latest earnings discussion with analysts, three facilities Calpine has under construction have been placed on the "discretionary" list (i.e.,

completion of construction is optional and no cash is forecast in the capital budget for completion). We believe that Hillabee is one of those three.

Q. **What is your reaction to Mr. Vogt's contention that a coal fired generation facility could be permitted within 18 months and available within 42 months in time to meet a June 1, 2010 need?**

A. He is indulging in some very wishful thinking. It is highly unlikely that LS Power could permit, build and bring to commercial operation a 900+ MW coal-fired unit in 60 months (5 years). I have been unable to identify any coal fired generation which LS Power has ever brought to commercial operation, much less in 5 years. It appears that LS Power's most advanced coal fired development project is in Osceola, Arkansas where initial permit applications were apparently filed in 2001. The company has reported an estimated commercial operation date in 2008 (seven years after the permits were filed), and a September 29, 2004 article in the *Kansas City Star* reports commercial operation is not expected until 2009 (eight years after the permits were filed).

AN RFP WOULD NOT BE IN THE INTERESTS OF FPL'S CUSTOMERS

Q. **Does the Commission's Bid Rule require FPL to conduct an RFP prior to seeking approval for the PPAs?**

A. It is my understanding that Rule 25-22.082, Florida Administrative Code (the "Bid Rule"), which requires utilities to issue RFPs in connection with generation additions subject to the Power Plant Siting Act, is not applicable to

these PPAs. When it adopted the Bid Rule, the Commission expressly considered and rejected the notion that RFPs should be required for all power purchase agreements. *See* September 19, 2002, Staff Recommendation, Docket No. 020398-EI, at p. 12; September 30, 2002, Special Agenda Conference to Consider Amendments to Rule 25-22.082, Florida Administrative Code, Tr. at pp. 166-168, 276-277.

Q. Nonetheless, would it not be consistent with the intent of the Bid Rule for FPL to conduct an RFP before seeking approval of the PPAs?

A. Again, no. First, let me point out that subsection (18) of the Bid Rule provides that, even for generation additions that are subject to the Bid Rule (which this PPA clearly is not), there are times when the utility needs the flexibility to make generation supply decisions for the sake of reliability and other benefits to its customers without being constrained by an RFP process.

This is one of those instances. Simply put, the timing of our negotiations with Southern Company would not have allowed us to conduct an RFP while still retaining the right to lock in the benefits of the as-negotiated PPAs. While those negotiations were under way, we considered but rejected the idea of conducting an RFP. The package of PPAs we were negotiating are good for FPL's customers. To issue an RFP instead would have required us to balance the likelihood of obtaining a better deal for our customers against the potential loss of benefits from the existing deal. For the reasons I discussed previously

in my rebuttal testimony, we did not see much likelihood of an RFP's yielding an alternative that offered all the benefits of the PPAs. If we wrote the RFP in a way that required all those benefits, Southern Company likely would have been the only acceptable bidder. It is not clear whether, had we taken that approach, Southern Company would have kept open the same terms and conditions of the PPAs that we had negotiated. On the other hand, if we wrote an RFP that did not require the benefits of the PPAs, we might have ended up with a clearly inferior alternative. For example, if we did not insist upon a coal component in the RFP, there would be no guarantee that any bidder, including Southern Company, would include a coal component. In short, the potential losses outweighed the potential gains.

THE PPAs ARE MORE BENEFICIAL TO FPL'S CUSTOMERS THAN ACCELERATING A SELF-BUILD ALTERNATIVE TO 2010

Q. Because the Net Present Value (NPV) cost associated with accelerating a self-build alternative to 2010 is lower than the NPV of the PPAs, why should FPL not choose the self-build alternative?

A. FPL believes that the benefits of the PPAs exceed those of a self-build alternative for several reasons. First, the PPAs offer FPL's customers a number of benefits that are not provided by a self-build alternative. My direct testimony lists and discusses these benefits. Although the exact magnitude of those benefits can only be determined through the exercise of the features in

the PPAs, if the PPAs are approved and become effective, the benefits are real and they are assured. In contrast, merchant witnesses Dismukes, Knauth and Vogt can only offer less than credible speculation as to whether FPL could or would be able to perhaps obtain some of those benefits, absent the PPAs. FPL's position is that ensuring that those benefits will be available is in the best interest of our customers. The comparison between the PPAs and the indicative self-build alternative was aimed exclusively at the two alternatives' relative costs, and did not address a comparison of all relevant benefits. The cost comparison was performed only to establish, as a threshold matter, that the price of the PPAs was within a reasonable range, not to make a final determination as to which alternative is better.

Second, the PPAs obligate FPL for only five and one half years, until the end of 2015. Therefore, if FPL determines by 2008 that technologies other than current design gas-fueled combined cycle units have been developed to the point that they offer economic advantages, along with the requisite high level of reliability, by 2015 FPL would be able to pursue these technologies.

Finally, the PPAs do not preclude FPL from adding self-build alternatives, or pursuing one or more proposals for purchase power that is or are determined to be better than a self-build alternative for the purpose of meeting FPL's growing capacity need in the future. In other words, if FPL's PPAs are approved, FPL will still have need for additional capacity in 2009, 2011,

2012, etc., and FPL will have to select self-build alternatives and/or other purchases to meet those needs. Therefore, entering into the PPAs does not preclude any of the other alternatives. In fact, one or more of the other alternatives will be required prior to the effective date of these PPAs.

THE BENEFITS OF THE PPAs MAY NOT BE AVAILABLE UNDER MARKET ALTERNATIVES

Q. The merchant witnesses suggest that the benefits of the PPAs likely could be obtained in connection with market alternatives to the PPAs. Do you agree?

A. No. This is yet another instance of their tempting the Commission to substitute speculation for certainty. Two of the PPAs' benefits illustrate this point well: the coal-fired capacity and the transmission roll-over rights that are available under the PPAs.

As I have previously discussed, one of FPL's central purposes in negotiating the PPAs was to retain significant coal-fired capacity for the benefits of our customers. We succeeded in this, despite the fact that coal-fired capacity is highly sought after, is in extremely short supply, and Southern Company has many other markets for such capacity. The merchant witnesses would have the Commission jeopardize FPL's entitlement to that coal-fired capacity in favor of unsubstantiated speculation that there might be other coal-fired

capacity available somewhere. The only example offered by merchant witness Dismukes is a plant in Louisiana, and it is not a viable option because of insurmountable transmission obstacles.

The merchant witnesses likewise offer nothing but conjecture concerning firm transmission rights on the Southern Company side of the interface, which both merchant witnesses Vogt and Dismukes have agreed are valuable. As I have previously discussed, FPL believes it has the right to roll over its transmission rights under the existing UPS Agreement but that in order to do so FPL expects it will have to show that there are no substantial changes in system flows caused by the change in delivery points. The delivery points FPL has selected under the PPAs will not result in substantial changes in system flows and therefore FPL has a strong argument that its roll-over request should be granted for these PPAs. In contrast, there is no assurance that this same argument would be available for delivery of power from other market resources.

Q. Does that conclude your rebuttal testimony?

A. Yes.

BY MR. LITCHFIELD:

Q Mr. Hartman, have you prepared a summary of your rebuttal testimony?

A Yes, I have.

Q Would you please provide that summary to the Commission.

A Good afternoon, Commissioners. You heard testimony about FPL's new UPS contracts from both myself and the merchant witnesses. I have shown why these contracts are a benefit for our customers and should be approved by this Commission. The merchant witnesses have given you no valid reason not to.

Approval of the contracts at this time is essential to preserve their benefits for our customers. The contracts allow us six months to obtain approval from this Commission. Absent such approval, there is no reason to expect Southern will be willing to enter into a later agreement on the same terms. Absent your approval now, we will be forced to start considering other options for replacing the expiring UPS agreement in 2010. Most likely this would be a self-build option, which would lose the benefits to our customers I have described in my direct testimony.

The testimony of the merchant witnesses begins and ends with speculation. But the real question is not how many merchant generators currently exist or could be built in the southeast. What really matters is how many facilities are

actually available that realistically could provide the benefits that we are seeking for our customers. These customer benefits include at least some component of firm coal-fired capacity, the ability to retain our existing transmission rights through roll-over, and enhanced reliability. There are very few existing merchant generators that can provide these benefits, and we are confident that we considered the relevant resource options.

As far as units in development or construction, whether they will be completed in time to meet our need is conjecture and we are unwilling to have our customers depend upon conjecture. The merchant witnesses claim that FPL should have conducted an RFP before entering into the new UPS, but an RFP is not in our customer's interest. This is one of those instances.

Consider the benefits these contracts bring to our customers. A total capacity of 930 megawatts to our system after the transmission losses. The ability to roll-over the existing transmission rights to the new contracts. At least 165 megawatts of firm coal generation. Firm gas transportation adequate to fuel the gas-fired facilities on a pipe other than FGT or Gulfstream. Rights of first refusal to 790 megawatts of coal generation, and a five-year term to allow us to consider other options. If these benefits were provided as a minimum requirement in an RFP, it is unlikely that anyone but Southern

could meet the requirements. If we relax the requirements, then we would not receive all the benefits these contracts bring with them.

Similarly, we recommend approval of these contracts instead of pursuing a self-build option, because the self-build option would not provide all the benefits of these contracts. The self-build analysis was performed as one of several reference points to see if the costs associated with the contracts are reasonable. Our assessment is that the contracts are indeed reasonable. And are, in fact, a superior alternative for our customers when the added benefits to the contracts are taken into account.

So why are the merchant witnesses so adamantly opposed to this UPS contract? Both Mr. Vogt and Mr. Knauth are employed by owners and developers of merchant generation. Mr. Dismukes is testifying on behalf of Mr. Churbuck. While Mr. Churbuck is an FPL residential customer, he is also president of a subsidiary of Calpine Corporation, another merchant generation developer.

It is in the best interests of the merchant industry for the Commission to reject these contracts regardless of whether they benefit FPL's customers. In contrast, FPL's only interest in these contracts is to secure the benefits for our customers.

Thank you for taking the time to consider these

issues. Again, I firmly believe the contracts are in our customers' best interest, and recommend the Commission approve the contracts for purposes of cost-recovery.

Q Does that conclude your summary, Mr. Hartman?

A Yes, it does.

MR. LITCHFIELD: Mr. Chairman, I would tender the witness for questioning.

CHAIRMAN BAEZ: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Hartman, at Page 12 of your rebuttal testimony, I believe you say that FPL did consider issuing an RFP when it was negotiating with Southern Company, is that correct?

A Where is that? On Page 12, you said?

Q My note says Page 12. Well, forgive me, if I gave you the wrong reference, but it is true, is it not, that in your rebuttal testimony you mentioned that FPL considered issuing an RFP with respect to this 955 megawatts?

A Yes, we did, and we rejected doing that.

Q But you considered doing that even though FPL's position was and is that the bid rule does not apply to this situation, correct?

A It is my understanding that the bid rule doesn't apply, therefore, we are not required to perform an RFP. We nonetheless considered if it would be in our customers' best

interest to do so and decided that it would be against their interest to conduct an RFP.

Q Is it true that Southern Company has submitted proposals to FPL in past RFPs?

A Yes, they have.

Q In your rebuttal you mentioned again the benefits associated with retaining transmission capacity, the firm transmission rights on Southern. Is it true that if FPL for whatever reason does not go through with the three UPS contracts that transmission will become available?

A That is correct, that transmission will no longer be used. The transmission, however, that becomes available is predominantly on our side of the interface.

Q With respect to that which is on the Southern side, as the former owner of those rights, would FPL have the ability to purchase those rights before it is placed on OASIS?

A No. If we cannot roll-over our rights on an existing contract, we have no more rights. We would have to file for firm transmission and go to the back of the queue.

Q Is there the possibility of obtaining those rights on an unbundled basis separate from the contracts?

A In order to roll-over our transmission rights, we need to have capacity contracts out there with someone to have a point to roll it over to.

Q Prior to joining FPL, you worked for FPL Energy, is

that correct?

A That's correct.

Q And that is the unregulated affiliate that is in the merchant business?

A That's correct.

Q While with FPL Energy, in your capacity with FPL Energy, did you submit wholesale proposals to purchasing utilities?

A Yes, we did.

Q And in doing so, were you sometimes competing against other contenders for that opportunity?

A Yes, sometimes.

Q While with FPL Energy, did you ever win any of those competitions?

A We won a few.

Q And when you won those, in your opinion were those transactions in ratepayers' interests?

A No, they were in my interest.

Q But do you believe that they were a good deal for ratepayers?

A I didn't care. As a merchant generator on the merchant side, my objective is to make money for my shareholders, let the utility worry about their ratepayers. I did not care.

Q All right. If the purchasing utility did its job,

would your proposal have been in the ratepayers' interest for you to have won it?

MR. LITCHFIELD: I will object to the question. I have no idea what he is asking.

CHAIRMAN BAEZ: Did you say you had no idea what he is asking or why he is asking?

MR. LITCHFIELD: It is vague. No, what. It is vague.

CHAIRMAN BAEZ: Can you clarify your question?

MR. McGLOTHLIN: Yes. The witness has characterized certain witnesses in this case as having interests different from those of ratepayers. My proposition is that the purchasing utility, if it does its job correctly, approves a transaction that is in its ratepayers' interests, and if the merchant wins there is an alignment of interest there.

CHAIRMAN BAEZ: Ask your question again.

BY MR. McGLOTHLIN:

Q Mr. Hartman, you said earlier that while with FPL Energy you were on the winning side of some competitions and succeeded in doing business with the purchasing utility. In your opinion, if the purchasing utility was doing its job to protect its ratepayers, do you believe that that transaction served ratepayers' interest?

A I believe that it is an obligation of the utility to serve its ratepayers, yes. Now, your question is is it my

opinion that the contracts that some of the people signed were in the ratepayers' best interest for their utility's customers. I neither knew, cared, nor evaluated it. I don't know what was in their ratepayers' best interests. If a utility is doing their job, they should protect their customers. That has not always been the case, and it has not always happened.

Q You have stated in your testimony that when with FPL Energy you negotiated PPAs for a period of time, did you not?

A Yes, we did.

Q You also negotiated amendments to PPAs?

A Yes, I did.

Q So you are familiar with the fact that PPAs can be amended in many respects when the parties to the transaction agree to do so.

A Amendments can be made to a PPA whenever the parties mutually agree to do so. The only time I amended a PPA was when it was in my company's interest to do so.

Q Do you believe it may sometimes be in the mutual interests of the parties to a PPA to extend an agreement?

A At times.

Q Do you think it may be in the parties' mutual interest to shorten an agreement?

A At times.

Q If it were in the interest of FPL's customers for FPL to shorten an existing PPA and the other party was willing to

do so, would you be in favor of seeing that happen?

A Yes, I would.

Q And assuming that happened, would the fact that FPL and another party shortened an agreement have any negative implications for FPL's willingness to adhere to its other obligations in other contracts?

A I don't understand the question.

Q Well, let me refer you to Page 10. With respect to Mr. Knauth, you say he suggests that perhaps Vandolah could terminate its commitment early. That is pretty speculative and does not exactly inspire confidence that any commitment made to FPL would be rejected.

My question is if the parties to a PPA for whatever reason mutually agree to shorten one contract, does that indicate any negative implications for their ability or their willingness to adhere to other obligations?

A Not necessarily. However, in this case Vandolah was indicating, at least to me, in their testimony that they would go back in and negotiate to get out of the contract or terminate the contract if a better deal came along. We are looking for firm resources. You know, if we wanted to renegotiate a contract from our side, we went in and it is in their best interest, fine. But what you are saying is that Vandolah was willing, or at least my indications were that Vandolah was willing to go ahead and renegotiate to get out of

a deal the first time a better deal came along. That is not what we are looking to do for our customers.

Q Well, wouldn't that happen only if, as you said earlier, there was a mutual willingness to shorten it?

A Yes, it would.

Q And, again, if that were the case, if it were a mutual agreement and in both parties' interests, would that indicate anything negative about either parties' willingness to adhere to other obligations?

A No. If both parties were willing to negotiate it, that would be fine.

Q While with FPL Energy, did you ever submit proposals for capacity that was not completed at the time you submitted the proposal?

A Yes, I did.

MR. McGLOTHLIN: No further questions.

CHAIRMAN BAEZ: Thank you, Mr. McGlothlin. Ms. Christensen, you indicated that you didn't have any?

MS. CHRISTENSEN: That's correct, we have no questions.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: I have some questions.

CROSS EXAMINATION

BY MR. MOYLE:

Q Mr. Hartman, do you recall working on an answer to an

interrogatory Mr. Churbuck served on you in which areas of expertise were asked about?

A Not particularly, no.

Q So you don't have any recollection about an interrogatory in which you could profess your areas of expertise?

A I don't remember exactly the interrogatory you are asking for.

Q Okay. Page 9 of your rebuttal testimony, down toward the bottom of it there you indicated that you elected not to include cogenerators in our screening. Do you see that on Line 20?

A Yes, I do.

Q And is the reason because they have certain minimal standards and that requirements are placed on the abilities of cogenerators to dispatch freely?

A Cogenerators typically as QFs have certain requirements under FERC regulations to maintain their status as a qualified facility. That has certain things to do with efficiency and thermal energy use. As a result of those requirements, you wind up with an operational restriction as far as how they can be dispatched normally without running afoul of those efficiency calculations.

Q Did you contact any cogenerators to see whether they had situations where they might be able to contract with you to

let you dispatch them?

A No, I did not. There wasn't any need to.

Q There wasn't a need to. Why not?

A Well, of the cogenerators that are out there, none of them are adequate to go ahead and fulfill a 950-megawatt load. In addition, they wouldn't be freely dispatchable as a cogenerator. They couldn't meet all the objections we need.

Q How about some portion? If maybe it wasn't 950, how about if you had cobbled together -- you know, coal is what you were after, as I understand it. If you did 165 of coal out of Scherer, and then found a cogenerator who had some coal, wouldn't that have been a better deal in terms of a better deal for FPL, if coal is what you were after, and a cogenerator was out there that had coal capacity available?

A What you are saying is instead of going with one creditworthy counter-party and one deal for 950 megawatts that we can swing the transmission on, we cobble together a large number of smaller units, and we did not consider doing that.

Q And I don't know how many large ones, but if I understand it, coal was the driver on this thing and you went down significantly in your coal. You didn't look at any cogenerators that might be out there that were coal-fired?

A I think you have mischaracterized the drivers of it. I have testified we have stated the objective was to maintain as many of the benefits of the UPS agreement that we currently

enjoy as possible. Part of it was coal, part of it is the transmission, part of it is other aspects.

Q Does FPL presently receive coal-fired capacity from cogenerators located in the State of Florida?

A Yes, we do.

Q And does FPL have dispatch rights over those cogenerators?

A Yes, we do.

Q Does FPL depend on those plants to provide it with reliable electricity to serve its native load?

A Let me point out a couple of things about them.

MR. MOYLE: Mr. Chairman --

A Yes, we do rely upon them to serve our native load. Yes, we do count on their capacity.

Q And you have dispatch rights, is that right?

A We have dispatch rights, but it is limited under the contract. It is certainly not as free as we have here. Also, it is public knowledge and it is filed in our FERC forms these units are hugely expensive.

CHAIRMAN BAEZ: Mr. Moyle, can I ask you to slow down on your questions and let the witness fully answer.

BY MR. MOYLE:

Q Okay. So if I understand your answer that you do have cogenerator coal facilities here in Florida that you rely

But in the process of looking at this UPS deal, you

scratched coal, you scratched all cogenerators off of your list from consideration, correct?

A Yes, we did.

Q And you also eliminated all plants in construction and in development, correct?

A Yes, we did. We were looking for existing plants that could meet our needs, not for something that may or may not be available.

Q And in part you said that was speculative, right?

A I believe signing up with a plant in construction would be speculative, yes.

Q Does FPL view its own plants that are in development and under construction as speculative?

A Because we are building them on our own balance sheet, no.

Q Only plants that are being built by others are speculative, is that right?

MR. LITCHFIELD: I will object to the characterization of the witness' testimony.

CHAIRMAN BAEZ: Ask your question again.

MR. MOYLE: I thought I had established that he scratched off plants that were in development and construction because they were speculative. And then I asked him if FPL considered its own plants that were in development and construction as speculative, and he said no. So my follow-up

was to say, well, then, other people that have plants in construction and development besides FPL, those power plants are considered speculative, is that correct?

THE WITNESS: Let me clarify first the answer. You mischaracterized it. I said no, we did not consider them speculative. I also said the reason why we did not consider them speculative is because we build them on our balance sheet, okay, which means we have the cash in hand to build the plant, and we go ahead and build it once we make the commitment to do so.

The reason why I say that plants in development are typically speculative is a very large number of plants that are announced ultimately don't get built. A fair number of plants that have announced and under construction haven't been built, and construction times and commercial operation dates continue to move, they are always getting later.

BY MR. MOYLE:

Q Okay. When FPL issues RFPs, it doesn't limit its scope to plants that are already in existence, does it?

A That's correct, we do not.

Q And don't you receive proposals from plants that are in development or under construction?

A Yes, we do.

Q And don't you try to protect yourself with things like step-in rights and performance bonds and guarantee

provision in these RFPs that you issue?

A Yes, we do. The one difference is this case is the value of the roll-over transmission.

Q And we have talked a lot about roll-over transmission, I don't know that we need to go back there right now. I'm trying to focus on these things, step-in rights, performance bonds, things like that. Did FPL consider contacting folks whose plants were in development or in construction and then making an effort to try to assure that it would receive energy out of those plants by contractually setting forth step-in rights, performance bonds, or guarantee provisions?

A No, we did not. We were looking at plants outside the State of Florida.

Q And there are plants outside the State of Florida that are in development, are there not?

A Yes, there are. However, it makes it much more difficult for our utility to step in on a power plant that is somewhere outside of the state. Within our territory it is fairly easy for us to do to protect our customers' interests.

Q But if I understand it, you have a power plant that you have an interest in in Georgia, Scherer, right?

A And it is operated by Southern Company for us.

Q Okay. A contract would be enforceable, would it not, if it were entered into between an entity in another state and

FPL with respect to things like step-in rights?

MR. LITCHFIELD: Object to the question. It is asking the witness for a legal conclusion.

CHAIRMAN BAEZ: Ask it.

BY MR. MOYLE:

Q Do you have any reason to know why a contract would not be enforceable if it were entered into by FPL, the regulated utility, and an energy provider who had a power plant in another state?

A No, I don't have any reason to know that, no.

Q You made a comment, I think, in your summary that you said you didn't think it was likely that even if you went out with an RFP and tried to get the same attributes that you were getting in this Southern deal that anybody would respond. Do you recall that?

A That is correct, that is what I said.

Q Okay. But you don't know that, do you?

A I'm trying to define the word know. There is nobody in the area that we could roll-over transmission to that has all of the benefits of this contract that have been enumerated in my testimony and elsewhere.

Q Wouldn't the way to determine that for sure is to go out into the market to make sure there is no one out there that could have provided you with a proposal that provided not identical, but similar benefits?

A The difficulty with doing that -- and, no, I don't necessarily agree with that -- is because we had a deal on the table that is good. There is no guarantee that Southern would keep that same deal. If Southern was out there and we were looking at all of this, we could be in a situation where if the minimum requirements are what we have on the table, they could jack the price up as a sole bidder. If the minimum requirements are less, then they could take away some of the things and still potentially be a winner, but we wouldn't get all the benefits.

Q You have, I think, testified in response to a question from Mr. McGlothlin that while with FPL Energy you responded to bid and things like that, is that correct?

A That is correct.

Q Was it your experience that when you were responding to an RFP that you usually had to sharpen your pencil pretty well because there were others out there that would be responding and you wanted to either win or make it in the top few to be considered?

A It depended on the particular bidding situation. If I thought that I had an economic advantage, and many times we thought we did, then rather than sharpening the pencil, I bid as high as I could to get onto the short list where I was negotiated. And rather than putting everything down in the lowest price, I put in a price where I could be extremely

profitable and yet still be in the running.

Q So if I understood you, you would bid to get into the game. And then when you would go to the negotiating table you would kind of hold maybe something a little back that you could put on the table later, is that right?

A No. What I was doing was bidding high enough that I could win. So it would be -- you know, if I could do a deal at a price of 2.4 cents, but I knew that the competition could do it at 4 cents, I would bid at 3.9.

Q How often did you have that kind of knowledge? Was it very often, regular, or was it a very rare occurrence?

A It was frequent.

Q You would know what other people would be bidding?

A No, I knew what their cost structure was, I new what the values were in the market, I knew what the competitive position was, and I knew my economies of scale and my capability of making a profit at it.

Q With respect to an RFP process, would you agree that having other bidders come in and make an offer to you could conceivably have put pressure on Southern to improve its price?

A It would depend very much on the nature of the RFP that we put out.

Q So dependent on the nature, it could have happened?

A Depending on the nature it could have happened. It could have also put pressure on them to increase the price as I

have earlier testified.

Q I had started asking you some questions about LS Power on your direct earlier today, and your lawyer objected to that. Do you recall that?

A I recall that.

Q Okay. On Page 12, Lines 11 and 12 of your rebuttal, I think you reference that project, do you not?

A Yes, I do.

Q Okay. Do you know if that plant has any unsubscribed power at this point in time?

A I don't know if the plant has any unsubscribed power whatsoever. I know a good bit about it. I think it is highly unlikely that plant will be on line in 2010. I know we requested from them their interconnection studies twice. I know we were in discussions with them in June. I know that we have requested background information and failed to get it. I know they came back to us for additional details about how to get the interconnection study. Given the status of the plant at this time, it is extremely unlikely that they are going to be there in 2010.

Q What did you ask them, for their studies, for the OASIS studies?

A I asked them for their interconnection studies and the load flow studies on the facility, which they had stated they had requested from Southern.

Q Did you check the OASIS to see if it had been requested?

A No, I did not. Since we were in meetings with LS Power, I thought it would be easier to just ask them for the study.

Q **You also reference a Big Cajun 2 unit in Louisiana?**

A Yes.

Q Do you know if that power plant has any unsubscribed power available?

A I don't know for a fact whether it does or not. I do know that Big Cajun is interconnected to Entergy. I would be looking at pancaked firm transmission rights to get it to Southern if I could get it around the constraint, so that would be about -- in the neighborhood of $3 per kilowatt month just for the firm transmission rights before I looked at in excess of 5 percent losses.

Q Five percent losses due to, what, transmission?

A Five percent losses to get it to where I would be picking it up on my roll-over.

Q Okay. And then you have further losses when you would move it down to your load center, correct?

A That is correct.

Q And what are those further losses, around 12 percent?

A We had some numbers out in the RFP. Of course, our computer models calculated otherwise, but in the 2003 RFP we

said it is about 12 percent from the Florida border down to our load center, and that is about right on a marginal basis.

Q So all of this information we have been talking about with respect to Southern, then you have whatever your losses are from Southern and then another 12 percent to get it down to your load center?

A And all of that has been incorporated in our economic analysis.

Q Do you know if permits have been obtained yet for the Big Cajun unit?

A Permits have been obtained?

Q Yes.

A I don't know

Q You do know it is over 1,700 megawatts of coal, don't you?

A That's correct. I know it is over 1,700 megawatts of coal. I know it is 42 percent owned by Entergy. I know a good bit about the interconnection on it. I know about the gas plants on it

Q Do you know anything about the transmission arrangements out of Big Cajun 2?

A No. There are some restrictions on energy coming into Southern's territory, I don't know what they are. I have not looked into them. The only reason why I looked at them was they have a pancaked rate, and that would be enough to make it

uneconomic.

Q So you don't know anything about the ability of the Big Cajun 2 plant to provide power products to FPL?

A No, I do not.

Q Okay. And you didn't contact the owners of the Big Cajun 2 plant?

A No, I did not.

Q You reference a staff recommendation on Page 13 of your rebuttal testimony. I think you're talking about the intent of the bid rule. Do you remember that?

A Yes, I remember that.

Q Do you recall anything in the staff recommendation that in any way suggested that contracts that were for longer than three years might be appropriate to be put out for bid under an RFP?

A I remember that there were some discussions about that and the issue was decided by the Commission not to go there. That they looked at where do you put a stop, whether the Commission can do it, et cetera, and the Commission decision didn't address that.

Q And they didn't decide that it was not required, they didn't say anything that you couldn't do it, correct?

A That is my understanding.

Q They just decided not to address it?

A That was my understanding.

Q Do you recall a similar discussion with respect to purchased power agreements of less than 150 megawatts?

A No, I don't.

Q We talked a little bit about the benefits, and I asked you the question about dispatchability of cogenerators, and is it true as we sit here today that the units that you have under this deal with Southern are fully dispatchable by FPL?

A Yes, they are.

Q Okay. And what does fully dispatchable mean?

A That means under the current agreements we can take power from the unit or not. We can tell them to deliver X number of megawatts at a particular time.

Q And what does AGC mean?

A ABC?

Q I'm sorry, ATC, AGC, something about automatic control you put in your PPAs that lets you run a power plant. Do you have any familiarity with that?

A I think you mean AGC, automatic generator control. That is not an issue here.

Q What is it?

A If you are saying AGC, it has to do with the capability of ramping the unit up or down remotely in steps.

Q So if something is fully dispatchable, is it fair to say you can kind of run it like your own in terms of

operations?

A Within some restrictions, yes.

Q Are there any restrictions that are placed on FPL with respect to how it is able to dispatch these units?

A Yes. Whenever we dispatch it, we can change the levels anywhere we want within technical limits and contractual limits. There is also a given amount of time when the units are dispatched off, they must have a minimum amount of off time when they are dispatched on, a minimum amount of on time. It depends on the unit.

Q Do you have to give them any minimum amount of advanced notice?

A We have to give them enough notice to go ahead and accommodate the scheduling.

Q We got a look at the letters of intent that I had asked you questions about, and I have some questions about that

MR. LITCHFIELD: I will object to the characterization. What I think Mr. Moyle is referring to is Exhibit 69.

MR. MOYLE: No, I'm sorry, I misspoke. The rights of first refusal, these letters on the right of first refusal. Are these 69?

MR. LITCHFIELD: Letter agreements representing the rights of first refusal.

CHAIRMAN BAEZ: 69.

BY MR. MOYLE:

Q Do you have those with you?

A No, I don't.

MR. MOYLE: Mr. Chairman, I don't have a whole lot longer.

CHAIRMAN BAEZ: I think counsel is going to help you out there.

THE WITNESS: Okay.

BY MR. MOYLE:

Q All right. You had filed testimony extolling the benefits of these rights of first refusal, correct?

A I believe I had filed testimony saying that the right of first refusal was one of the benefits that we have as a result of these contracts, yes.

Q And you don't have to look at these contracts to answer these questions, but what is your understanding of a right of first refusal?

A A right of first refusal to me in the case of these agreements means two things; we got a little bit more than a straight up right of first refusal.

MR. MOYLE: Mr. Chairman, I'm not asking in the context of these agreements, I'm asking him in general terms what he understands the right of first refusal to be.

MR. LITCHFIELD: Then I would object, because I think that is a very vague question.

CHAIRMAN BAEZ: Start over again and ask him --

BY MR. MOYLE:

Q Not referencing these agreements, in general understanding, what do you understand a right of first refusal to be?

A A general right of first refusal to me would be if somebody has a deal, they bring it to us first and we can either accept it or reject it.

Q Okay. And you would agree, given that definition, that you have one right of first refusal and the other is a right to negotiate, correct, with respect to these two letters?

A And which one are you characterizing as which?

Q There is one in here that has language, and a lot of it has been redacted, but it says that -- it appears to require a notice that if you desire to purchase the capacity and energy associated with the additional Scherer capacity that is not sold to the third party, then you give notice and then you, and I quote, "Execute a binding agreement in substantially the form of the Scherer PPA where SCS shall sell, and FPL shall purchase all of the capacity and energy from the subject Scherer capacity." So I guess that would be the Scherer document, is that correct?

A That is what the document appears to say as a broad summary.

Q So, this is for 75 megawatts, is that right?

A That's correct.

Q And this deal essentially is like a backup contract in real estate. Are you familiar with the term backup contract in real estate?

A Yes, I am.

Q And would you agree that that is a fair comparison?

A I would agree that the terms here are basically, if their existing deal falls through, that we will get the -- or we have the opportunity to negotiate 75-megawatts of addition to the existing Scherer PPA, basically.

Q And you don't have to sit down and negotiate, or anything, you basically execute an agreement with terms already established, correct?

A There is going to have to be some negotiation.

Q In substantially the same form as the Scherer PPA?

A That is correct.

Q All right. And I was looking at the other document, and I didn't see any similar language in there about providing notice and then all of a sudden executing a binding agreement. And it is not in that other document, is it? And the other document, I'm talking about the Miller document.

A There is not an equivalent to the Scherer PPA in the Miller document.

Q Doesn't the Miller document really represent, rather than a right of first refusal, a right to negotiate?

A No. Actually I think the Miller agreement is more than a right of first refusal. At first shot we have the right to negotiate. If we can't reach agreement, they are free to go off and try to market it to somebody else. If they reach agreement with somebody else, they then have to bring it back to us on those same terms.

At that point we have a true right of first refusal, because they have negotiated the deal, we have the right to accept it or reject it at the equivalent terms. So on the Miller agreement I think we effectively have two bites at the apple. If we negotiate a deal that is acceptable for our customers, that is great, we are done. If we don't think the deal is acceptable for our customers, they get to go try and get somebody else to do it. If the other deal is different, we get a chance to have it.

Q Let me refer you to Page 3. The last sentence of Paragraph 6 says, "However, neither party shall be required to enter into any agreement for the purchase or sale of the subject Miller capacity." Does that indicate to you that there is no requirement, no firm requirement in this right of first refusal that a deal has to be done between you and Southern with respect to the Miller capacity?

A It is clear that there isn't a requirement that we have to do a deal. I don't understand how you can have a right of first refusal that requires that you do the deal.

Q I just saw the document two hours ago, and --

A I understand. I mean, clearly if we try to negotiate a deal with Miller, and we don't believe it is in our customers' interest, we tell Southern no, it is not a good deal. They then go out and try and market it to someone else. If they come to a different deal with someone else, they then have to bring it back to us. We then can still take a look at it and say this is a good deal or not. There is no requirement that we sign a contract.

Q You negotiated on behalf of -- contracts on behalf of the subsidiary of Florida Power, I guess it is Florida Power and Light Energy, is that right?

A FPL Energy is an affiliate, yes.

Q Did you ever negotiate in a situation in which somebody came to you and said, hey, I want to do a deal with you, but understand if we strike a deal you may not get it. I have to take it back to another person. Did that ever happen to you?

A No, not that I can recall.

Q If that was presented to you, would you kind of be less inclined to really roll up your sleaves and strike a deal knowing that you might not get it at the end of the day?

A It depends on the deal.

Q A couple more questions. Do you know if FPL Energy presently sells power to Southern?

A I believe FPL Energy does have a contract with Alabama Power, I believe.

Q Okay. Do you know if it has a contract with any other Southern affiliates?

A I don't know.

Q Do you know if any wind power of FPL Energy is being sold to Southern or any subsidiaries of Southern?

A I don't know of any.

Q The question with respect to the value of these contracts, we had talked earlier and I think you had said there was a two percent difference in the cost of your self-build gas plants as compared to the Southern gas, is that right?

A Under certain simplifying assumptions and at the busbar, yes.

Q Okay. And I asked you if you could put a dollar figure on that, and you said you could not, correct?

A Oh, you asked for a dollar figure in terms of total number of megawatt hours over the life of the contract reflected in that price. And the answer is no, right as I sit here right now I don't have that number.

Q Let me ask you to get the number if this is what you would have to do. There are 8,460 hours in a year, correct, or do you know that?

A 8,760, actually.

Q Okay. So you would take that number, and you

multiply it by, what, five and a half years?

A Yes, to pick up the number of hours in five and a half years.

Q And then you would multiply that number by the megawatts of gas that you are getting from Southern?

A Well, you have an issue there as to how much we have the plants turned on.

Q What is the capacity factor typically for a combined cycle unit?

A Well, the issue isn't typically, because we have the arbitrage opportunity, so we might have these things off more. So you can't exactly just say, all right, a typical combined cycle plant might be 50 to 60 percent. That doesn't necessarily work because the dispatch patterns will be different.

Q Do you know what the dispatch patterns would be?

A Not offhand, no.

Q Because that is dependent on the market conditions and arbitrage, we talked about that?

A It is incorporated in our computer models, and I have not gone in and looked at hour=to-hour and year-to-year as to what the output was. I looked at an NPV basis.

Q All right. And I think you had testified earlier that there was about a dollar per megawatt hour difference, is that correct?

A In that neighborhood, yes, at a particular assumption in terms of gas price and everything else.

Q And subject to check, if you took the 8,760 number of hours in a year times -- I timed it by 5 to be conservative, times 790 megawatts of gas, and you assumed a dollar, I came up with a total dollar amount of 33 million bucks. And then I guess you would have to adjust that based on a capacity factor of maybe 50 percent. So 16 million bucks. Is that a significant amount of money in your view?

MR. LITCHFIELD: Let me object first to ask if counsel is asking the witness to confirm his math?

CHAIRMAN BAEZ: Mr. Moyle.

BY MR. MOYLE:

Q Can you confirm my math? That's a dangerous question.

A Well, your initial start didn't have enough hours in the year, so I would want to see it in writing before I would try and confirm it.

Q Okay. Well, just for the record, just give me -- the formulaic approach is correct. Number of hours in the year, times the years of the contract, times the megawatts of gas, correct?

A Times the dispatch.

Q Times the dispatch, times the dollar per megawatt?

A Times roughly a dollar a megawatt.

Q Assume for purposes of my question that applying a 50 percent capacity factor it came to $16 million. Would that, in your view, be considered a significant sum of money?

A Given the fact that I have already testified that the estimate used for the engineering on the pricing was not down to the nth degree yet, not down to the point where we have an RFP, I would consider $16 million well within the realm of round off error.

MR. MOYLE: I am tempted to ask you if you ever worked with the Congressional Budget Office, but I won't and I will end my questions.

CHAIRMAN BAEZ: Staff.

CROSS EXAMINATION

BY MS. VINING:

Q Mr. Hartman, let's say that FPL does get roll-over transmission rights, and these agreements are approved by the Commission for cost-recovery purposes. Does that mean that FPL would own that firm transmission for the period of 2010 to 2015, or would FPL own them ad infinitum?

A We would own them under the contracts that would be put into place until 2015. Come 2015 or before then, we would have to decide what we would do to continue them, if it was in the customers' best interest to continue them.

Q So it is possible at that point in time you could attempt to negotiate another similar agreement with Southern

Company?

A Absolutely. And it wouldn't necessarily be with Southern. We would be in a position where we would have rolled over transmission, if it was still in our customers' best interest to have power from up there and arbitrage it, we would be taking a look at what to do.

MS. VINING: Thank you.

CHAIRMAN BAEZ: No further questions, Ms. Vining?

MS. VINING: I'm sorry. Yes, no further questions.

CHAIRMAN BAEZ: Thank you. Commissioners, any questions?

Mr. Litchfield, redirect?

MR. LITCHFIELD: Just a couple on redirect, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. LITCHFIELD:

Q Mr. Hartman, do you remember Mr. McGlothlin asking you about parties reaching a mutual agreement to amend a purchased power agreement?

A Yes, I do.

Q In cases where such a mutual agreement is reached, in your experience is there typically any consideration paid by one party to the other to amend that contract?

A If somebody is terminating a contract and is shortening it, I would expect cash to flow from one party to

another.

Q Mr. Moyle asked you several questions about LS Power, and I believe in your response you indicated that, indeed, you had met with LS Power, that you had requested certain information, and that it had not yet been provided. Is that an accurate recollection of your testimony?

A Yes, it is.

Q Mr. Vogt, who appeared from LS Power as a witness in this proceeding, do you recognize him as having attended any of those meetings?

A I remember him as attending the meeting, yes.

MR. LITCHFIELD: No further questions.

CHAIRMAN BAEZ: Okay. Mr. Litchfield, I'm showing Exhibits 19 and 20.

MR. LITCHFIELD: Thank you. We would move those into the record at this time, Mr. Chairman.

CHAIRMAN BAEZ: Without objection, show 19 and 20 entered into the record.

(Exhibits 19 and 20 admitted into the record.)

CHAIRMAN BAEZ: And I think that about does it, Mr. Hartman. Thank you for your testimony.

THE WITNESS: Thank you.

CHAIRMAN BAEZ: All right. Commissioners, I think that does it for the witnesses. At this point we had mentioned that we were holding off on one remaining issue that we didn't

get to earlier today. I think it was 14B.

MS. VINING: Yes, 14B. But before we do that, I think there is a few of the exhibits that were not moved into the record from the witnesses that were stipulated.

CHAIRMAN BAEZ: You're absolutely right. Let's go back.

MS. VINING: And Mr. Keating has been keeping a record of that and he can speak to that.

CHAIRMAN BAEZ: We can go by my list. I have Exhibits 1 through 10, 11, 12, 21 through 30, and 35 through 40, 47 and 48.

MR. KEATING: That is consistent with what I've got.

CHAIRMAN BAEZ: All right. And without objection, show those exhibits moved into the record. That should complete all of those items listed in Exhibit 1, including Exhibit 1.

MS. VINING: Yes.

(Exhibits 1 through 12, 21 through 30, 35 through 40, 47 and 48 admitted into the record.)

CHAIRMAN BAEZ: As well as those that have been presented at hearing. All right.

MR. MOYLE: Mr. Chairman, just so I am clear, this is the list that was handed out at the beginning that we are referring to?

CHAIRMAN BAEZ: Correct.

MR. MOYLE: And Mr. Dismukes' stuff came in and it is in the record?

CHAIRMAN BAEZ: Mr. Dismukes' stuff I'm showing was admitted.

MR. MOYLE: Okay.

MS. VINING: Yes, it was admitted after his live testimony.

CHAIRMAN BAEZ: I think we're square. Anything else before we get to the recommendation?

MS. VINING: I don't believe so.

CHAIRMAN BAEZ: Okay. Commissioners, we had one item left over, not including Item 4C, which will be the subject of a written recommendation at this point. That would be Item 14B.

MS. VINING: Correct.

CHAIRMAN BAEZ: And I think, staff, are you able to make an oral recommendation at this point for a bench vote?

MR. HAFF: Yes.

CHAIRMAN BAEZ: Mr. Haff.

MR. HAFF: Thank you, Commissioners. Issue 14B reads should the Commission require FPL to explore other alternatives in the wholesale market prior to seeking approval of the purchased power agreements.

And staff recommends no. FPL already did make inquiries to potential providers in the wholesale market. FPL

did not receive any satisfactory offers. Further, the Commission's bid rule does not require a utility to go through the request for proposals process when the utility extends a purchased power contract prior to these contracts going into effect. FPL plans to issue an RFP for its 2009 need, and at that time the wholesale power market will have an opportunity to submit alternatives.

CHAIRMAN BAEZ: Commissioners, any questions on 14B?

COMMISSIONER DEASON: If there are no questions, I can move approval of staff's recommendation.

CHAIRMAN BAEZ: There is motion. Is there a second?

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Motion and a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, staff. Any winding up issues that we have got to take up?

MS. VINING: Yes. There is one late-filed exhibit. I believe that is the map that Commissioner Deason requested.

CHAIRMAN BAEZ: That's correct.

MS. VINING: And we need to set a date for the filing of that.

CHAIRMAN BAEZ: We need to set a date, because I don't think we did.

MS. VINING: Right. I think FPL indicated that they

November 17th, which will then have the brief due on Issue 14C on December 1st. The staff rec on the issue will be due December 21st, going to the January 4th agenda. And the order is technically due 20 days after that, which would be the 24th of January, and that is what the CASR will read, but I will make every effort to have the order issued before that date.

CHAIRMAN BAEZ: Very well. Anything else? Anything else the parties need to bring before the Commission at this point? No?

I want to thank all the parties for their contribution, the witnesses for their testimony, and some witnesses in particular for their patience as to the slowness. And this is a very involved process, so we appreciate those of you that had to wait for a couple of days, and those of you that had to be on the stand for a couple of days.

And I want to thank staff for all their hard work, as well. Believe it or not, as long as this hearing seemed and as contentious, it could have been much worse, and we owe that to your good work.

And lastly, Commissioners, thanks for sitting by me. You could dialed it in, but you didn't, and I appreciate it. We are adjourned. Everyone have a good night and thank you.

MR. BUTLER: Thank you, Commissioners.

(The hearing concluded at 5:32 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

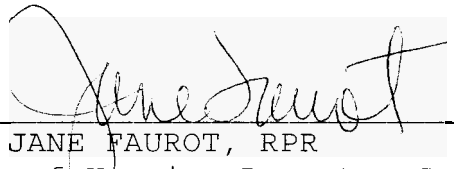
COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 17th day of November, 2004.



JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
Staff			
1		Exhibit List-Stip- 1	Comprehensive Stipulated Exhibit List
2		Composite Stip-2	FPL's Response to Staff's 4th Set of Interrogatories, No. 34
			FPL's Response to Staff's 5th Set of Interrogatories, Nos. 35-46
			FPL's Response to Staff's 6th Set of Interrogatories, No. 47
			FPL's Response to Staff's 7th Set of Interrogatories, No. 48
			TECO's Response to FIPUG's 1st Set of Interrogatories, No. 6
			FPL's A9 Schedule, 2000-2003
			Gas Daily October 29, 2004, Forecast, p. 5
Testimony Exhibit List			
FPL			
3	G. Yupp	(GJY-1)	Hedging Information
4	G. Yupp	(GJY-2)	Appendix I/Fuel Cost Recovery Forecast Assumptions
5	K. M. Dubin	(KMD-1)	Appendix I and II Fuel Cost Recovery and Capacity Cost Recovery
6	K. M. Dubin	(KMD-2)	Final True-Up Calculation – Jan. 2003 – Dec. 2003
7	K. M. Dubin	(KMD-3)	Appendix I and II /Fuel Cost Recovery and Capacity Cost and Recovery Estimated
8	K. M. Dubin	(KMD-4)	Actual True-Up for Jan. 2004 – Dec. 2004
9	K. M. Dubin	(KMD-5)	Appendix II/Fuel Cost Recovery E Schedules, Levelized Fuel Cost Recovery Factors for Jan. 2005 – Dec. 2005
10	K. M. Dubin	(KMD-6)	Appendix III/Capacity Cost Recovery Factors for Jan. 2005 – Dec. 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 1
COMPANY/ F.P.S.C. Staff
WITNESS: Exhibit List- Stip-1
DATE 11-08-04

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
11	P. Sonnelitter	(PS-1)	GPIF, Performance Results Jan. 2003 – Dec. 2003
12	P. Sonnelitter	(PS-2)	GPIF, Targets and Ranges, Jan. 2005 – Dec. 2005
13	T. L. Hartman	(TLH-1)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
14	T. L. Hartman	(TLH-2)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
15	T. L. Hartman	(TLH-3)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
16	T. L. Hartman	(TLH-4)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
17	T. L. Hartman	(TLH-5)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
18	T. L. Hartman	(TLH-6)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
19	T. L. Hartman	(TLH-7)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
20	T. L. Hartman	(TLH-8)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
FPUC			
21	George M. Bachman	(GMB-1)	Composite. Schedules E1-A, E1-B, E1-B1 (for the Marianna and Fernandina Beach Divisions)

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
22	George M. Bachman	(GMB-2) (revised)	Composite. Schedules E1, E1-A, E2, E7, E8, and E10 (for the Marianna and Fernandina Beach Divisions)
GULF			
23	H. R. Ball	(HRB-1)	Coal Suppliers January 2003 – December 2003
24	H. R. Ball	(HRB-2)	Projected vs. actual fuel cost of generated power March 1995 – December 2005
25	T. A. Davis	(TAD-1)	Calculation of Final True-Up 1/03 – 12/03
26	T. A. Davis	(TAD-2)	Estimated true-up 01/04 – 12/04, Schedules E-1A, E-1B, E-1B-1, CCE-1a, CCE-1b
27	T. A. Davis	(TAD-3)	Projection -1/05 – 12/05, Schedules E-1 through E-11, H1, CCE-1, CCE-1A, CCE-1b, CCE-2
28	L. S. Noack	(LSN-1)	Gulf Power Company GPIF Results January 2005 – December 2003
29	L.S. Noack	(LSN-2)	Gulf Power Company GPIF Targets and Ranges January 2005 – December 2005
30	H. Homer Bell, III	(HHB-1)	Gulf Power Company Projected Purchased Power Contract Transactions January 2005 – December 2005
PEF			
31	Javier Portuondo	(JP-1T)	True-up Variance Analysis, Capacity Cost Recovery True-up, Tiger Bay Amortization, and Schedules A1 – A9 (December 2003).
32	Javier Portuondo	(JP-1R)	Reprojection Assumptions (Parts A-C), Capacity Cost Recovery Reprojections (Part D), and Schedules A1 – A9 (July 2004).
33	Javier Portuondo	(JP-1P)	Forecast Assumptions (Parts A-C), Capacity Cost Recovery Factors (Part D), Hines 2 Depreciation & Return Calculations (Part E), and Schedules E1 – E10 and H1 (2005).

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
34	Javier Portuondo	(JP-1S)	Updated E Schedules and Hines 2 Depreciation and Return Schedule
35	Pamela R. Murphy	(PRM-1T)	2003 Risk Management Plan Results Summary, and Hedging Information Summary.
36	Pamela R. Murphy	(PRM-1P)	2005 Risk Management Plan.
37	Michael F. Jacob	(MFJ-1T)	GPIF Reward/Penalty Schedules
38	Michael F. Jacob	(MFJ-1P)	GPIF Targets/Ranges Schedules
39	Samuel S. Waters	(SSW-1)	Shady Hills Tolling Agreement
40	Samuel S. Waters	(SSW-3)	Shady Hill Cost/Benefit Summary
TECO			
41	J. Denise Jordan	(JDJ-1)	Fuel Cost Recovery Jan. 2003 – Dec. 2003 Capacity Cost Recovery Jan. 2003 – Dec. 2003
42	J. Denise Jordan	(JDJ-2)	Fuel Cost Recovery, Projected Jan. 2004 – Dec. 2004 Capacity Cost Recovery, Projected Jan. 2004 – Dec. 2004
43	J. Denise Jordan	(JDJ-3)	Fuel Cost Recovery, Projected Jan. 2005 – Dec. 2005 Capacity Cost Recovery, Projected Jan. 2005 – Dec. 2005
44	J. Denise Jordan	(JDJ-4)	Incremental Security Costs
45	David R. Knapp	(WAS-1)[1]	Generating Performance Incentive Factor Results Jan. 2003 – Dec. 2003
46	David R. Knapp	(DRK-1)	Generating Performance Incentive Factor Estimated Jan. 2005 – Dec. 2005
47	Joann T. Wehle	(JTW-1)	Calculation of 2003 Incremental Hedging Operations and Maintenance Costs.

[1] Adopted by Witness David. R. Knapp

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
48	Joann T. Wehle	(JTW-2)	2003 Transportation Benchmark Calculation 2003 Transportation Market Price Application Calculation of 2005 Projected Incremental Hedging Operations and Maintenance Costs.
CHURBUCK/FIPUG			
49	David E. Dismukes	(DED-1)	Contribution of Contracts to Total Purchase Agreement
50	David E. Dismukes	(DED-2)	Merchant Facilities Located in Proximity to Contracted Units
51	David E. Dismukes	(DED-3)	Estimated Natural Gas Transmission Capacity
52	David E. Dismukes	(DED-4)	Merchant Development in SERC Region
53	David E. Dismukes	(DED-5)	Merchant Development in SERC by Subregion
54	David E. Dismukes	(DED-6)	Merchant Development in FRCC Region
55	David E. Dismukes	(DED-7)	Merchant Facilities Under Construction in SERC
56	David E. Dismukes	(DED-8)	Merchant Facilities Under Development in SERC
57	David E. Dismukes	(DED-9)	Merchant Alternatives in SERC
58	David E. Dismukes	(DED-10)	Planned Transmission Additions (Circuit Miles)

EXHIBIT NO. _____

DOCKET NO: 040001-EI

WITNESS: VARIOUS

PARTY: FLORIDA POWER & LIGHT CO.
TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF STIPULATED DOCUMENTS:

1. FPL'S RESPONSE TO STAFF'S 4TH SET OF INTERROGATORIES (NO. 34);
2. FPL'S RESPONSE TO STAFF'S 5TH SET OF INTERROGATORIES (NOS. 35-46);
3. FPL'S RESPONSE TO STAFF'S 6TH SET OF INTERROGATORIES (NO. 47);
4. FPL'S RESPONSE TO STAFF'S 7TH SET OF INTERROGATORIES (NO. 48);
5. FPL'S SCHEDULE A9, 2000 – 2003;
6. TAMPA ELECTRIC'S RESPONSE TO FIPUG'S 1ST SET OF INTERROGATORIES (NO. 6);
7. *GAS DAILY,* OCTOBER 29, 2004, PAGE 5

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 2
COMPANY/ F.P.S.C. Staff
WITNESS: Composite Stip-2
DATE: 11-08-04

Q. On page 15 of witness Hartman's direct testimony filed in this proceeding, he discusses a cost differential of $60 to $80 million (2004 NPV) between the cost of FPL's self-build option compared to the cost of the proposed contracts. Please describe in detail how this cost differential was calculated.

A. The economic analysis was based on production costing simulations, similar to those normally used by FPL for economic evaluation of power supply alternatives. For the PPAs, the inputs to the analysis were based on the contractual commitments and costs. A self-build generic 4 x 1 combined cycle facility was developed for comparison using currently estimated costs and operational characteristics. For purposes of transmission loss calculations, the self-build facility was assumed to be similar to a plant located at Corbett.

Excluding transmission-related costs on FPL's system, equity adjustment, and ability to arbitrage the firm transmission capacity associated with the PPAs, the analysis indicates a self-build facility could have NPV costs of $107 million lower than the PPAs. Additionally, the PPAs have an equity adjustment of $17 million associated with them, which would increase this differential to $124 million. Finally, our analysis of system costs for the PPAs is based upon marginal losses, and totals $117 million for energy and capacity losses. If we self build a unit instead of using the PPAs, this transmission capacity would likely be used by others to import power into Florida. In this instance, the energy and capacity losses would still occur, but we would recover a portion of this through our tariff rates on transmission. Our tariff rates are based upon average losses, not marginal. Average system losses are 2.19%. Assuming marginal losses of 13% from the border as disclosed in the 2003 RFP, and assuming we recover 2.19% under the tariff, this would increase the differential by $19.7 million, for a total of $144 million. Both the self build unit and the PPAs have redispatch costs associated with loads in South Florida. The PPA redispatch costs are $9 million higher than the self build, due to the fact that the self build unit is assumed closer to the load center. The total cost differential between a self build unit and the PPAs is $153 million, before considering the benefit of retaining transmission in SERC.

We have estimated that the ability to use the firm transmission to purchase economy energy in SERC has a net present value benefit of up to $83 million, with an average estimate of $60 million. Offsetting these benefits against the $153 million cost differential described above yields a net result of a self-build unit a NPV cost of $69 million to $93 million lower than the PPAs. This calculation does not attempt to quantify the other economic benefits (beyond arbitrage) identified in witness Hartman's Direct Testimony.

Q. Please identify whether FPL's existing purchased power contracts with Southern Company contain deadlines for FPL to seek contract renewal or extension.

A. It does not, nor does it imply that renewal or extension is part of the contract.

Q. Please describe any dispatch rights FPL will have for Scherer Unit 3, Harris Unit 1, and Franklin Unit 1 under the proposed contracts.

A. Output of each of the PPA units is fully dispatchable by FPL. Scheduling parameters for each unit are provided in Appendix D of each unit's respective agreement.

Q. Page 5, lines 6-8 of witness Hartman's testimony states that the total capacity under the proposed contracts is 930 MW after allowance for transmission losses. Please identify the amount of these losses, as well as any additional losses resulting from delivery over FPL's system to its load center in Southeast Florida.

A. Per Southern's OASIS system, as of August 2004, capacity losses on Southern's transmission system are 2.0%, or 19.1 MW. These losses are calculated using an average system loss factor. FPL estimates incremental capacity losses are 66 MW attributable to the PPAs, based upon marginal loss calculations. These marginal losses have been reflected in FPL's economic analysis of the PPAs.

Q. Please discuss the conditions under which Southern Company or Southern Power Company could terminate the proposed contracts.

A. See TLH-1 (Sherer) ¶ 5.14.3; ¶ 7.4.6; ¶ 14.2.1: See TLH-2 (Harris) ¶5.15.3; ¶7.4.6; ¶16.2.1 : See TLH-3 (Franklin) ¶5.15.3; ¶7.4.6; ¶16.2.1

Q. Page 6, lines 13-15 of witness Hartman's testimony discusses FPL's right to terminate the proposed contracts if "unable to obtain adequate firm transmission by a date certain..." Please identify the "date certain", and discuss any reasons why FPL would not be able to obtain the required transmission rights.

A. December 1, 2005. We know of no reason why transmission would not be granted. Under Southern's Open Access Transmission Tariff, however, applications for firm transmission can take up to 240 days to be granted. Although it is expected that FPL's transmission rollover request will be granted prior to the end of 2004, the deadline of December 1, 2005 was established to accommodate the longest possible approval schedule, with a small amount of margin.

Q. Pages 7 and 8 of witness Hartman's testimony discuss FPL's securing of transmission rights for the proposed contracts. Please describe who grants the authority to "roll-over" existing transmission rights and how this is done.

A. "Roll-Over" is granted by the transmission owner, in this case, Southern Transmission. A filing was made on Southern's OASIS system to request the roll-over on August 25th. This was followed up with an e-mail confirming the filing, and payment of one month's transmission fees as security. We have also requested that the firm transmission be redirected to the new generating plants, under the PPAs. Southern will examine the feasibility of transmitting power from these facilities to a delivery point on FPL's system. They will then either grant the roll-over and redirect, or indicate that a facilities study is needed.

If a study is required, the facilities study would identify the cost and schedule to perform any system upgrades necessary to provide the requested transmission service. FPL would then be advised of the availability and cost of the transmission service, and given an opportunity to accept or reject Southern's proposal. The process is disclosed in Section 19 of Southern's Open Access Transmission Tariff.

Q. Please discuss whether FPL's proposed contracts use network or point-to-point transmission service. If point-to-point, please identify these locations.

A. The proposed contracts anticipate FPL using firm point to point service. The receipt points are the Harris, Franklin and Scherer plants. The delivery point in each instance is FPL's interconnection with the Southern transmission system.

Q. Please identify the anticipated cost of transmission rights under the proposed contracts.

A. Transmission service is provided at cost of service based rates, under Southern's OATT. At present, the service cost is $1,753.52/MW-Month, plus scheduling fees of $80.60/MW-month.

Q. Page 9, lines 12-14 and 19-22 of witness Hartman's testimony discusses FPL's ability to retain 930 MW of firm transmission within SERC to buy market energy and capacity as a benefit. Please describe how this is a benefit when the transmission capacity is expected to be used up by the proposed contracts. Please include an explanation of how this benefit would be any different if FPL did not have the proposed contracts.

A. The benefit discussed applies to the use of the firm transmission when the facilities under contract are not being dispatched. If the market price for energy is lower than the dispatch cost of the plants, and lower than our own system's marginal cost, we can choose to not dispatch our contract units, and instead purchase cheaper power in the market and bring it to our system using the transmission rights. If the market price is higher than our dispatch cost of the plants under contract, and these dispatch costs are lower than our system's marginal costs, then we dispatch the plants under contract and use the transmission to bring the power to our customers. If the dispatch cost of the plants under contract is lower than the market price, but higher than our own system marginal costs, we would dispatch the plants under contract to the extent we can sell the output into the market. All of these options allow us to lower the cost of energy to our customers by using the firm transmission benefit. If FPL did not have the proposed contracts, we would also not have firm transmission in Southern's territory, and none of these options would apply.

Q. Page 12, lines 1-4 of witness Hartman's testimony states that off-peak power purchases could result in savings of between $36 million and $83 million. Please identify whether these savings are over the contract term or over some other period, and provide the net present value analysis, on an annual and cumulative basis, to determine anticipated savings.

A. The savings are net present value in 2004 dollars of savings anticipated over the term of the contracts. Analysis is provided below:

Conversion of Projected Arbitrage Savings to NPV 2004$ Values

		Minimum Arbitrage		Maximum Arbitrage	
Year	Annual Discount Factor 0.0793	Nominal Annual Arbitrage Savings	NPV Annual Arbitrage Savings	Nominal Annual Arbitrage Savings	NPV Annual Arbitrage Savings
2004	1.000	0	0	0	0
2005	0.927	0	0	0	0
2006	0.858	0	0	0	0
2007	0.795	0	0	0	0
2008	0.737	0	0	0	0
2009	0.683	0	0	0	0
2010	0.633	6,981,073	4,416,407	18,033,360	11,408,370
2011	0.586	13,908,277	8,152,261	31,651,714	18,552,481
2012	0.543	12,930,363	7,022,202	28,350,420	15,396,503
2013	0.503	13,664,620	6,875,717	34,197,875	17,207,569
2014	0.466	12,435,827	5,797,662	27,455,777	12,800,059
2015	0.432	13,911,761	6,009,221	27,862,328	12,035,204
		73,831,921	38,273,470	167,551,474	87,400,186

Q. Page 12, lines 12-14 of witness Hartman's testimony identify the arbitrage value of transmission rights for 2003 as $10.87 million. Please explain whether this value is net of the cost of transmission rights.

A. Yes, in the sense that the incremental cost for arbitrage of the transmission rights is zero. The cost of transmission is associated with the costs of the PPAs and has been reflected in the economic analysis as part of the cost of the PPAs. Since the cost of the transmission must already be paid as part of the PPAs, the ability to arbitrage (and the benefit to our customers) has zero incremental cost associated with it.

Q. Page 15, lines 16-18 of witness Hartman's testimony states that acceleration of FPL's self-build plan could result in savings of between $60 ($69*) million and $80 ($93*) million versus the cost of the proposed contracts. Please identify whether these savings are over the contract term or over some other period, and provide the net present value analysis, on an annual and cumulative basis, to determine anticipated savings.

***These figures have been changed to reflect FPL's correction to page 15 of Hartman's Direct Testimony. The replacement page was filed on October 20, 2004. This change does not affect the conclusions or results reflected in the testimony of Mr. Hartman.**

A. The question paraphrases my testimony. I testified that "if we were to consider only the costs that can be readily quantified," accelerating FPL's self build plan could result in lower costs, but went on to add that "this would ignore a number of the benefits of the PPAs that are not easily quantified but, represent real opportunities and value for our customers."

The purpose of the limited comparison between the contracts and a self-build option was not to provide a full evaluation of one alternative against another for selection purposes. Rather, it was to determine whether the price of the contracts was "reasonable." The result of the comparison confirmed that the price of the proposed PPAs is indeed reasonable.

The cost comparison was performed on a net present value basis, over a period of 30 years. This form of analysis is the most appropriate way to compare the impact on FPL's system from different power-supply alternatives, but it does not yield meaningful year-by-year cost comparisons. Therefore, the following discussion applies to the cumulative net present value difference only.

The table below summarizes the results of FPL's cost comparison:

NET PRESENT VALUE ($ MILLIONS)

	Maximum Arbitrage	Average Arbitrage
System Generation Model Differential	$ (107)	(107)
Equity Adjustment	$ (17)	(17)
Redispatch cost differential	$ (9)	(9)
Energy & Capacity Losses	$ (117)	(117)
	$ (250)	(250)
Potential Benefit of SERC Transmission	$ 83	60
Marginal energy & capacity losses due to wheeling by others	$ 117	117
Transmission loss recovery under tariff	$ (20)	(20)
Net differential between PPA & self build	$ (69)	(93)

Negative numbers reflect self build less costly than PPAs
Numbers may not add due to rounding

The following describes each of the entries in the table:

- System generation model differential. This provides the NPV of the differential production costs on our entire system of having the PPAs in our portfolio versus a self built unit.

- Equity adjustment. This adjustment reflects the cost associated with the balance sheet impact of PPAs in FPL's portfolio, as used by the rating agencies.

- Redispatch cost differential. This differential recognizes the value associated with local grid benefits of a self-built unit in South Florida, which purchased power transmitted from SERC cannot provide.

- Energy and capacity losses. This reflects the cost differential between the marginal losses of capacity and energy on FPL's transmission system associated with the PPAs, and those associated with a self-build alternative in South Florida.

- Potential Benefit of SERC Transmission (arbitrage). FPL will be able to use the firm transmission obtained through the PPAs to purchase economy energy in SERC and wheel it to its customers in Florida, a practice referred to as arbitrage. FPL estimates the value of this arbitrage opportunity at a high of $83 million and an average of $60 million.

- Marginal Energy and Capacity Losses Due to Wheeling By Others/Transmission Recovery Under Tariff. If FPL were to elect a self-build unit instead of the PPAs, the transmission capacity FPL currently utilizes to supply our customers for the existing UPS agreement would become available. In such circumstance, it is reasonable to expect that third parties would utilize the transmission capability to import power from SERC, and the losses associated with such transaction would still be experienced. Since under FPL's transmission tariff transmission customers are responsible for the average transmission losses associated with a transaction instead of the marginal losses, FPL's customers would be responsible for the difference between the marginal losses and the average transmission losses associated with the third party transaction. FPL's average transmission losses under the Tariff are 2.19%. FPL estimates that its customers would have to absorb $117 million in marginal transmission losses, which appears in the table under the heading "Marginal Energy and Capacity Losses Due to Wheeling By Others." This would be partly offset by the recovery of an estimated $19.7 million of these losses through the tariff's average transmission losses recovery procedures. This offset is reflected in the $(20) million entry labeled "Transmission Loss Recovery Under Tariff."

- Net Differential Between PPA and Self-Build. This reflects the arithmetic sum of the gains and losses described above. As shown in the table, the net differential is $69 million based on the high arbitrage estimate and $93 million based on the average arbitrage estimate.

It is important to note that this differential does not reflect any value for the other benefits of the PPAs that are not provided by a self-build alternative. These benefits include retention of some firm coal fired capacity as part of the contracts; the planning flexibility afforded by these short-term contracts, especially when combined with long-term commitments as part of an overall strategy; enhanced system reliability through the geographic diversity of the PPA units, as well as the independent firm gas transportation commitment provided by the PPAs. FPL's position is that these benefits definitely outweigh the cost differential reflected in the table.

Q. **In FPL's response to staff interrogatory #44, you identify the annual and cumulative dollar savings associated with economy energy purchases. Could you please provide the expected amount of economy energy purchases, the average transaction cost of these purchases, and the cost if such energy was generated?**

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A. The following table presents the information requested for both minimum and maximum projected economy energy purchases, on a non-discounted basis, consistent with our answer in Staff's Interrogatory No. 44.

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Year	Projected Amount of Economy Energy Purchases (GWh) Minimum	Projected Amount of Economy Energy Purchases (GWh) Maximum	Projected Average Transaction Cost of Economy Energy Purchases (000) Minimum	Projected Average Transaction Cost of Economy Energy Purchases (000) Maximum	Avoided Projected Cost of Generation of Economy Energy Purchases (000) Minimum	Avoided Projected Cost of Generation of Economy Energy Purchases (000) Maximum	Projected Value of Economy Energy Purchases (000) Minimum	Projected Value of Economy Energy Purchases (000) Maximum
2010	[redacted]						$ 6,981	$ 18,033
2011							$ 13,908	$ 31,652
2012							$ 12,930	$ 28,350
2013							$ 13,665	$ 34,198
2014							$ 12,436	$ 27,456
2015							$ 13,912	$ 27,862
							$ 73,832	$ 167,551

CONFIDENTIAL

Q. Please provide a side by side comparison of the costs contained in the proposed Harris Unit PPA compared to the costs of FPL's self-build combined cycle alternative. Please provide the same analysis for the proposed Franklin Unit PPA. Costs should be provided for both capacity ($/kw-mo) and energy (¢/kwh). Also, please include the MW size, fuel cost assumption in $/MMBTU, and operating assumptions such as capacity factor, heat rates, etc.

A. The figures requested are provided in the table on page 2 of this response, but should be viewed with caution. Relative cost comparison can be skewed by a number of factors, including how the units are dispatched and how they are operated. These factors would influence start costs and effective heat rate (steady state operation at the most effective output has the best heat rate). In the table below we have assumed the most effective heat rates for the units, a capacity factor slightly lower than we would expect for a self build, and slightly higher than we would expect for Harris and Franklin, but the same values.

Additionally, of course, these figures do not reflect the other aspects of the agreement which bring additional value to the PPAs. These include some firm coal generation , increased reliability due to both geographic diversity and the additional pipeline, the ability to purchase economy energy from the market, as well as the timing flexibility the limited duration PPAs provide to address other generation options, and the ability to preserve firm transmission rights in SERC even beyond the expiration of the PPAs.

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		Self Build	Harris	Franklin
Capacity	MW	1144	600	190
Capacity Payment	$/kW-Month	[redacted]		
Heat Rate	Btu/kWh			
Variable O&M	$/MWh			
Start Charge	$/start			
Fuel Transportation	$/MMBtu			
Assumptions				
	Gas price $/MMBtu	6.00	6.00	6.00
	Capacity Factor	60%	60%	60%
	Starts/year	50	50	50
	Production (MWh)	6,012,864	3,153,600	998,640
Cost Comparison				
	Capacity Cost	[redacted]		
	Variable O&M			
	Start Charges			
	Fuel			
	Fuel Transportation			
	Total Cost			
	Cost/MWh	[redacted]		

[redacted]

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY FLORIDA POWER & LIGHT COMPANY
FOR THE MONTHS OF JANUARY THROUGH DECEMBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS COST cents/KWH	TOTAL $ FOR FUEL ADJ (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ACTUAL							
FLORIDA							
Florida Power Corporation	OS	241,565	3 079	7,436,607	3 783	9,138,687	1,702,080
Homestead, City of	OS	10	8 000	800	8 290	829	29
Lake Worth, City of	OS	799	13 089	104,582	13 468	107,609	3,027
New Smyrna Beach Utilities Comm, City of	OS	90	4 000	3,600	4 986	4,487	887
Orlando Utilities Commission	OS	167,125	7 318	12,230,126	7 451	12,453,182	223,056
Reedy Creek Improvement District	OS	2,000	4 916	98,319	5 152	103,042	4,723
Ridge Generating Station	OS	4,520	3 808	172,105	4 732	213,906	41,801
Seminole Electric Co-op	OS	1,260	3 356	42,285	4 514	56,880	14,595
Tallahassee, City of	OS	7,335	3 344	245,285	5 071	371,954	126,669
Tampa Electric	OS	138,663	2 750	3,813,323	3 511	4,868,700	1,055,377
The Energy Authority	OS	474,908	2 924	13,885,007	3 771	17,907,224	4,022,217
NON-FLORIDA							
Allegheny Energy Supply	OS	802	5 765	46,237	7 214	57,860	11,623
American Electric Power Svc Corp	OS	28,923	4 318	1,248,811	4 851	1,403,009	154,198
Aquila Energy Marketing	OS	148	7 478	11,067	10 086	14,927	3,860
Aquila Power Corp	OS	6,452	4 478	288,926	5 541	357,515	68,589
Cargill-Alliant, LLC	OS	46,443	4 062	1,886,352	4 714	2,189,246	302,894
Carolina Power & Light	OS	9,773	3 421	334,383	4 515	441,273	106,890
Coral Power	OS	16,472	8 371	1,378,842	8 727	1,437,439	58,597
DTE Energy Trading	OS	5,949	5 636	335,288	5 380	320,075	(15,213)
Duke Energy Trading	OS	6,171	4 352	268,544	5 719	352,932	84,388
Duke Power	OS	49,130	4 978	2,445,608	5 056	2,483,873	38,265
Dynegy Power Marketing	OS	14,057	4 734	665,497	0 000	737,129	71,632
East Kentucky Power Corp	OS	1,299	1 460	18,963	2 934	38,116	19,153
El Paso Merchant Energy	OS	227	5 419	12,302	6 729	15,274	2,972
Enron Power Marketing	OS	21,652	4 968	1,075,777	5 918	1,281,386	205,609
Entergy Power Marketing	OS	12,147	4 867	591,202	5 355	650,505	59,303
Entergy Services	OS	0	0 000	(18,763)	0 000	0	18,763
Koch Energy Trading	OS	27,776	4 368	1,213,255	4 524	1,256,513	43,258
LG&E Energy Marketing	OS	191,440	3 154	6,037,967	4 062	7,777,190	1,739,223
Louisville Gas & Electric	OS	8,440	2 816	237,636	3 640	307,234	69,598
Morgan Stanley Capital Group	OS	113,002	4 134	4,671,533	4 961	5,605,765	934,232
North Carolina Municipal Power Agency	OS	5,888	1 546	91,008	2 106	123,978	32,970
Oglethorpe Power Corp	OS	75,233	3 330	2,505,336	0 000	3,113,283	607,947
PG&E Energy Trading-Power LP	OS	435	2 481	10,794	3 263	14,192	3,398
PJM Interconnection LLC	OS	2,255	6 491	146,375	4 351	98,113	(48,262)
Reliant Energy Services	OS	3,503	5 389	188,774	6 161	215,835	27,061
Sempra Energy Trading	OS	8,845	4 231	374,235	5 588	494,236	120,001
South Carolina Electric & Gas	OS	7,468	3 219	240,376	4 167	311,155	70,779
Southern Company Energy Marketing	OS	546	2 327	12,707	2 576	14,066	1,359
Southern Company Services	OS	18,719	3 118	583,650	4 458	834,566	250,916
TXU Energy Trading	OS	5,318	4 171	221,814	4 437	235,952	14,138
Tenaska Power Services	OS	3,430	2 631	90,234	3 628	124,442	34,208
Virginia Electric & Power	OS	37,934	4 277	1,622,475	4 553	1,727,266	104,791
Vitol	OS	0	0 000	2,020	0 000	0	(2,020)
Williams Energy Marketing & Trading	OS	451	5 564	25,095	5 965	26,902	1,807
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,038,275	3 663	38,032,039	4 356	45,226,500	7,194,461
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		730,328	3 952	28,864,320	4 664	34,061,247	5,196,927
TOTAL		1,768,603	3 782	66,896,359	4 483	79,287,747	12,391,388

SCHEDULE A9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTHS JANUARY 2001 THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL $ FOR FUEL ADJ. (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ACTUAL:							
FLORIDA:							
THE ENERGY AUTHORITY	C	0	0.000	0	0.000	0	0
CITY OF HOMESTEAD	OS	192	2.174	4,174	3.051	5,858	1,684
CITY OF LAKE WORTH	OS	11	2.500	275	3.682	405	130
CITY OF LAKELAND	OS	4,010	7.543	302,482	8.839	354,458	51,976
CITY OF TALLAHASSEE	OS	1,409	1.919	27,044	2.700	38,049	11,005
FLORIDA POWER CORPORATION	OS	414,501	2.398	9,937,847	3.871	16,046,857	6,109,010
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0.000	3,206	0.000	0	(3,206)
ORLANDO UTILITIES COMMISSION	OS	96,628	5.980	5,778,096	6.295	6,083,119	305,023
REEDY CREEK IMPROVEMENT DISTRICT	OS	55	5.245	2,885	6.282	3,455	570
RIDGE GENERATING STATION, LP	OS	4,986	3.988	198,846	4.279	213,363	14,516
TAMPA ELECTRIC COMPANY	OS	48,816	2.999	1,463,927	3.441	1,679,487	215,560
THE ENERGY AUTHORITY	OS	523,297	3.925	20,537,658	4.419	23,122,379	2,584,721
NON-FLORIDA:							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	1,919	2.891	55,487	3.406	65,370	9,883
AMERICAN ELECTRIC POWER SERVICE CORPORATION	OS	33,283	5.367	1,786,232	6.602	2,197,280	411,048
AQUILA ENERGY MARKETING CORPORATION	OS	19,987	3.729	745,309	4.809	961,173	215,864
CALPINE ENERGY SERVICES, LP.	OS	420	8.024	33,700	8.074	33,912	212
CARGILL -ALLIANT, LLC	OS	147,876	4.010	5,930,185	4.416	6,530,668	600,483
CAROLINA POWER & LIGHT COMPANY	OS	7,036	3.621	254,761	5.118	360,109	105,348
CORAL POWER LLC	OS	18,138	4.361	789,132	4.969	901,203	112,071
DUKE ENERGY TRADING & MARKETING, LLC	OS	79,172	3.154	2,496,804	3.796	3,005,402	508,598
DUKE POWER, A DIVISION OF DUKE ENERGY CORP.	OS	3,628	3.667	133,050	4.643	168,436	35,386
DYNEGY POWER MARKETING, INC.	OS	22,991	2.828	650,159	3.569	820,456	170,297
EL PASO MERCHANT ENERGY, LP	OS	6,493	3.672	238,438	4.289	278,480	40,042
ENRON POWER MARKETING, INC.	OS	21,166	4.316	913,621	4.985	1,055,188	141,567
ENTERGY-KOCH TRADING, LP	OS	19,853	4.079	809,824	4.603	913,922	104,098
HARDEE POWER PARTNERS LIMITED	OS	1,200	5.800	69,600	8.109	97,308	27,708
L G & E ENERGY MARKETING, INC.	OS	168,370	3.821	6,433,240	4.419	7,439,558	1,006,317
LOUISVILLE GAS & ELECTRIC CO.	OS	100	3.000	3,000	4.272	4,272	1,272
MIRANT AMERICAS ENERGY MARKETING, LP	OS	70	3.000	2,100	3.829	2,680	580
MORGAN STANLEY CAPITAL GROUP, INC.	OS	177,516	5.532	9,820,229	5.759	10,223,027	402,798
NRG POWER MARKETING, INC.	OS	9,524	3.081	293,423	3.818	363,588	70,165
OGLETHORPE POWER CORPORATION	OS	47,744	3.658	1,746,445	4.506	2,161,369	404,924
PG&E ENERGY TRADING-POWER, LP	OS	104	4.188	4,356	4.291	4,463	108
RELIANT ENERGY SERVICES, INC.	OS	12,393	3.127	387,493	4.087	506,552	119,059
SEMPRA ENERGY TRADING CORPORATION	OS	12,478	3.658	456,496	4.603	574,399	117,904
SOUTH CAROLINA ELECTRIC & GAS CO	OS	10,748	4.225	454,117	5.404	580,794	126,677
SOUTHERN COMPANY SERVICES, INC.	OS	22,016	3.763	828,436	4.652	1,024,169	195,733
TENASKA POWER SERVICES CO.	OS	1,229	2.955	36,316	3.486	42,839	6,523
TXU ENERGY TRADING CO.	OS	6,731	3.508	236,114	4.081	274,662	38,548
WILLIAMS ENERGY MARKETING & TRADING	OS	72,337	2.739	1,981,130	3.199	2,313,758	332,628
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,093,904	3.497	38,256,440	4.347	47,547,430	9,290,990
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		924,521	4.066	37,589,197	4.640	42,895,037	5,305,841
TOTAL		2,018,425	3.758	75,845,637	4.481	90,442,467	14,596,830

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
YTD 2002

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL $ FOR FUEL ADJ. (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ESTIMATED:							
FLORIDA	OS	30,000	8.100	1,829,945	8.619	2,585,845	755,900
NON-FLORIDA	OS	120,000	3.400	4,080,000	3.848	4,617,600	537,600
TOTAL		150,000	3.940	5,909,945	4.802	7,203,445	1,293,500
ACTUAL:							
FLORIDA:							
THE ENERGY AUTHORITY	C	0	0.000	0	0.000	0	0
CITY OF HOMESTEAD	OS	92	8.674	7,980	9.992	9,193	1,213
CITY OF LAKE WORTH	OS	80	11.583	6,950	11.813	7,088	138
CITY OF LAKELAND	OS	1,900	1.826	34,700	2.092	39,757	5,057
CITY OF TALLAHASSEE (prior month adj)	OS	160	4.033	6,452	4.844	7,750	1,298
FLORIDA POWER CORPORATION	OS	472,735	2.071	9,790,427	3.506	18,584,902	8,794,475
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0.000	0	0.000	0	0
ORLANDO UTILITIES COMMISSION	OS	70,972	4.723	3,352,278	5.162	3,678,061	325,783
REEDY CREEK IMPROVEMENT DISTRICT	OS	0	0.000	0	0.000	0	0
RIDGE GENERATING STATION, LP	OS	690	3.504	24,175	3.668	25,309	1,134
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	19,144	3.562	681,945	4.613	883,117	201,172
TAMPA ELECTRIC COMPANY	OS	18,747	2.817	528,049	3.271	613,267	85,218
THE ENERGY AUTHORITY	OS	634,758	3.619	22,973,645	4.376	27,778,966	4,803,321
NON-FLORIDA:							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	3,831	3.523	134,968	3.997	153,143	18,175
AMERICAN ELECTRIC POWER SERVICE CORPORATION - PRIOR MO ADJ.	OS	7,365	5.209	383,667	8.099	449,167	65,500
AQUILA ENERGY MARKETING CORPORATION	OS	62,124	2.580	1,602,500	3.037	1,886,475	283,975
BP ENERGY COMPANY	OS	42	3.143	1,320	3.521	1,479	159
CALPINE ENERGY SERVICES, L.P.	OS	8,590	2.928	251,308	3.683	333,522	82,214
CARGILL -ALLIANT, LLC	OS	408,937	3.571	14,602,725	4.115	16,828,455	2,225,730
CAROLINA POWER & LIGHT COMPANY (Prior Mo. Adjust.)	OS	2,288	2.713	62,080	3.752	85,839	23,759
CINCINNATI GAS & ELECTRIC CO.	OS	5,492	4.380	240,555	5.679	311,896	71,341
CINERGY CAPITAL & TRADING, INC.	OS	0	0.000	37	0.000	0	(37)
CONOCO, INC.	OS	1,525	3.128	47,699	3.847	58,670	10,971
CONSTELLATION POWER SOURCE, INC.	OS	10,932	6.227	680,685	7.660	837,438	156,753
CORAL POWER LLC	OS	1,677	4.678	78,453	4.766	79,919	1,466
DUKE ENERGY TRADING & MARKETING, LLC	OS	73,006	3.309	2,415,946	4.061	2,979,539	563,593
DUKE POWER, A DIVISION OF DUKE ENERGY CORP.	OS	1,735	4.212	73,085	4.749	82,390	9,305
DYNEGY POWER MARKETING, INC.	OS	45,267	3.752	1,698,442	4.534	2,052,439	353,997
EL PASO MERCHANT ENERGY, LP (prior mo adj)	OS	162	3.163	5,124	3.472	5,624	500
ENRON POWER MARKETING, INC.	OS	0	0.000	0	0.000	0	0
ENTERGY-KOCH TRADING, LP	OS	72,959	3.687	2,835,792	4.403	3,212,640	376,848
EXELON GENERATION COMPANY, LLC	OS	50	2.700	1,350	5.422	2,711	1,361
HARDEE POWER PARTNERS LIMITED	OS	210	4.833	10,150	6.627	13,916	3,766
L G & E ENERGY MARKETING, INC.	OS	220,667	3.398	7,497,500	4.037	8,909,266	1,411,766
MIRANT AMERICAS ENERGY MARKETING, LP	OS	9,144	5.192	474,720	5.512	503,984	29,264
MORGAN STANLEY CAPITAL GROUP, INC.	OS	253,806	3.938	9,969,434	4.511	11,449,311	1,459,877
NORTHERN STATES POWER COMPANY	OS	22	2.964	652	3.473	764	112
NRG POWER MARKETING, INC.	OS	2,316	1.884	43,627	2.916	67,543	23,916
OGLETHORPE POWER CORPORATION	OS	27,404	3.244	888,862	3.643	1,053,029	164,167
RELIANT ENERGY SERVICES, INC. (prior mo adj)	OS	52,280	3.778	1,974,436	4.499	2,351,261	376,825
SELECT ENERGY, INC.	OS	6,400	3.907	250,072	4.396	281,361	31,289
SEMPRA ENERGY TRADING CORPORATION	OS	0	0.000	0	0.000	0	0
SOUTH CAROLINA ELECTRIC & GAS CO	OS	6,950	3.626	251,973	4.167	291,009	39,036
SOUTHERN COMPANY SERVICES, INC.	OS	26,221	3.808	998,587	5.206	1,365,095	366,508
TENASKA POWER SERVICES CO.	OS	7,851	3.026	237,589	3.505	275,170	37,581
TXU ENERGY TRADING CO. (prior mo adj)	OS	642	2.201	14,131	3.197	20,527	6,396
WILLIAMS ENERGY MARKETING & TRADING	OS	120,165	2.990	3,593,477	3.477	4,177,795	584,316
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,219,256	3.068	37,406,801	4.070	49,625,410	12,218,809
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,440,040	3.565	51,340,946	4.175	60,121,377	8,780,431
TOTAL		2,659,296	3.337	88,747,547	4.127	109,746,787	20,999,240
CURRENT MONTH:							
DIFFERENCE		2,509,296	(0.603)	82,837,602	(0.675)	102,543,342	19,705,740
DIFFERENCE (%)		1,672.9	(15.3)	1,401.7	(14.1)	1,423.5	1,523.4
PERIOD TO DATE:							
ACTUAL		2,659,296	3.337	88,747,526	4.127	109,746,780	20,999,255
ESTIMATED		2,353,245	3.553	83,621,741	4.342	102,177,982	18,556,242
DIFFERENCE		306,051	(0.216)	5,125,785	(0.215)	7,568,798	2,443,013
DIFFERENCE (%)		13.0	(6.1)	6.1	(5.0)	7.4	13.2

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
YTD 2003

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS COST cents/KWH	TOTAL $ FOR FUEL ADJ (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ESTIMATED							
FLORIDA	OS	702,001	3 177	22,301,798	4.224	33,011,523	10,709,728
NON-FLORIDA	OS	1,071,892	3 816	40,898,409	4 196	46,893,849	5,795,440
TOTAL		1,773,893	3 563	63,200,205	4 493	79,705,372	16,505,168
ACTUAL							
FLORIDA							
THE ENERGY AUTHORITY	C	0	0 000	0	0 000	0	0
ENERGY AUTHORITY, THE	OS	430,999	4 175	17,995,891	5 200	22,410,314	4,414,823
FLORIDA POWER CORPORATION	OS	704,048	2 985	21,016,137	4 615	32,489,219	11,473,082
HOMESTEAD, CITY OF	OS	150	9 500	14,250	10 741	16,112	1,862
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0 000	0	0 000	0	0
LAKELAND, CITY OF	OS	402	6 192	24,892	9 697	38,983	14,091
LAKE WORTH, CITY OF	OS	0	0 000	0	0 000	0	0
NEW SMYRNA BEACH UTILITIES COMMISSION, CITY OF	OS	0	0 000	0	0 000	0	0
ORLANDO UTILITIES COMMISSION	OS	108,675	5 681	6,173,472	6 355	8,905,991	732,519
REEDY CREEK IMPROVEMENT DISTRICT	OS	0	0 000	0	0 000	0	0
RIDGE GENERATING STATION, LP	OS	748	4 518	33,797	5 517	41,267	7,470
SEMINOLE ELECTRIC COOPERATIVE, INC	OS	50,248	3 790	1,904,241	4 888	2,454,462	550,221
TALLAHASSEE, CITY OF	OS	5,061	5 946	302,125	6 800	345,501	43,375
TAMPA ELECTRIC COMPANY	OS	17,761	3 909	693,896	5 141	912,802	218,705
NON-FLORIDA							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	805	4 210	33,933	5 789	46,661	12,728
AMERICAN ELECTRIC POWER SERVICE CORPORATION	OS	0	0 000	0	0 000	0	0
AQUILA MERCHANT SERVICES, INC	OS	0	0 000	0	0 000	0	0
BP ENERGY COMPANY	OS	240	6 125	14,700	6 551	15,722	1,022
CALPINE ENERGY SERVICES, L P	OS	24,540	7 263	1,787,154	8 749	2,146,998	359,834
CARGILL POWER MARKETS, LLC	OS	528,180	4 815	25,430,534	5 544	29,281,352	3,850,818
CAROLINA POWER & LIGHT COMPANY	OS	16,589	3 573	592,718	5 042	836,432	243,714
CINCINNATI GAS & ELECTRIC CO	OS	0	0 000	0	0 000	0	0
CONOCO PHILLIPS CO	OS	24,822	2 942	730,348	4 396	1,091,155	360,807
CONSTELLATION POWER SOURCE, INC	OS	0	0 000	0	0 000	0	0
CORAL POWER, LLC	OS	0	0 000	0	0 000	0	0
DUKE ENERGY TRADING & MARKETING, LLC	OS	7,088	4 940	350,168	6 862	486,363	136,194
DUKE POWER, A DIVISION OF DUKE ENERGY CORP	OS	(102)	5 000	(5,100)	5 705	(5,819)	(719)
DYNEGY POWER MARKETING, INC	OS	560	6.085	33,962	7 603	42,577	8,615
EL PASO MERCHANT ENERGY, LP	OS	0	0 000	0	0 000	0	0
ENTERGY-KOCH TRADING, LP	OS	55,358	4 621	2,557,918	5 571	3,083,836	525,919
EXELON GENERATION COMPANY, LLC	OS	0	0 000	0	0 000	0	0
HARDEE POWER PARTNERS LIMITED	OS	547	7 151	39,115	8 764	47,939	8,824
L G & E ENERGY MARKETING, INC.	OS	257,140	3 931	10,108,226	5 010	12,881,749	2,773,522
MIRANT AMERICAS ENERGY MARKETING, LP	OS	0	0 000	0	0 000	0	0
MORGAN STANLEY CAPITAL GROUP, INC.	OS	105,588	4 348	4,590,954	4 997	5,276,748	685,794
NORTHERN STATES POWER COMPANY	OS	0	0.000	0	0 000	0	0
NRG POWER MARKETING, INC.	OS	0	0.000	0	0 000	0	0
OGLETHORPE POWER CORPORATION	OS	9,811	2 397	235,160	3 965	388,960	153,800
PROGRESS VENTURES, INC	OS	88,904	3 585	3,098,054	4 322	3,755,762	657,708
RELIANT ENERGY SERVICES, INC	OS	18,497	5.149	952,411	5 940	1,098,661	146,249
SELECT ENERGY, INC	OS	0	0 000	0	0 000	0	0
SEMPRA ENERGY TRADING CORPORATION	OS	0	0.000	0	0 000	0	0
SOUTH CAROLINA ELECTRIC & GAS CO	OS	0	0 000	0	0 000	0	0
SOUTHERN COMPANY SERVICES, INC	OS	285,290	3 924	10,409,549	4 939	13,102,453	2,692,905
TENASKA POWER SERVICES CO	OS	1,714	6 288	90,640	7 496	128,459	37,818
TRACTEBEL ENERGY MARKETING, INC.	OS	0	0 000	0	0 000	0	0
TXU ENERGY TRADING CO	OS	0	0.000	0	0 000	0	0
VIRGINIA POWER ENERGY MARKETING, INC	OS	0	0 000	0	0 000	0	0
WILLIAMS ENERGY MARKETING & TRADING	OS	0	0 000	0	0.000	0	0
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,318,102	3 654	48,158,501	4.978	65,614,450	17,455,949
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,403,572	4.350	61,050,455	5 251	73,706,007	12,655,553
TOTAL		2,721,674	4.013	109,208,956	5 119	139,320,457	30,111,501
CURRENT MONTH							
DIFFERENCE		0	0	0	0	0	0
DIFFERENCE (%)		0.0	0 0	0 0	0 0	0 0	0 0
PERIOD TO DATE							
ACTUAL		2,721,674	4 013	109,208,957	5 119	139,320,457	30,111,501
ESTIMATED		1,898,484	3 947	74,936,176	5 224	99,178,091	24,242,816
DIFFERENCE		823,190	0.065	34,272,781	(0.105)	40,141,366	5,868,685
DIFFERENCE (%)		43.4	1 7	45.7	(2 0)	40.5	24 2

6. With regard to TECo's purchased power contract with Hardee Power Partners, Ltd. (HPP), provide the following information:

a. The date of completion of the sale of TECo's affiliate interest in the Hardee Power Station; and

b. List each item of cost in the purchased power contract between TECo and Hardee Power Partners, Ltd (HPP) that has changed since the date the sale was completed, providing:
   i. the effective date of the change in cost;
   ii. the charge before the change in cost; and
   iii. the charge after the change in cost for each item identified.

A. a. The sale of TECO Power Service's interest in Hardee Power Partners, Ltd., closed on September 30, 2003.

b. There were no changes to Tampa Electric's purchased power contract since the completion of the sale.

recent quarter; a year ago it delivered 18.3 million Dt.

The company's interstate gas transmission and storage business reported earnings of $8 million during the period, a 2% increase. Questar Pipeline transported a total of 17.9 million Dt in the latest quarter, down from the 18.3 million Dt a year ago. RAW

EIA: Storage surplus narrows with 26-Bcf injection

U.S. gas storage operators injected a net 26 Bcf during the week ending Oct. 22, raising working gas inventories to 3.249 Tcf with just a week remaining in the traditional refill season, the Energy Information Administration reported Thursday.

The surplus from the year-ago level shrank to 128 Bcf from 157 Bcf, while the surplus over the five-year average narrowed to 210 Bcf from 221 Bcf. EIA's five-year average showed an injection of 35 Bcf and total working gas of 3.039 Tcf.

Estimated working gas in storage

(week ending Oct 22)

	This Week (Bcf)	Last Week (Bcf)	Change (Bcf)
Consuming Region East	1,894	1,880	14
Consuming Region West	422	418	4
Producing Region	933	925	8
Total U.S.	3,249	3,223	26

	This Week Last Yr. (Bcf)	Prior 5 Year Average (Bcf)
Consuming Region East	1,847	1,832
Consuming Region West	396	376
Producing Region	878	832
Total U.S.	3,121	3,039

Source: Energy Information Administration

The build was on the low end of market expectations, which had ranged from the mid-30s to high 40s Bcf. Nevertheless, the report helped spark a rally on the December NYMEX gas futures contract, which broke the $9/MMBtu level before retreating (*see related story, page 2*).

Scott De Pasquale, senior analyst with Energy Security and Analysis in Boston, said that while the NYMEX "is sensitive now to any news," the contract's strong bullish reaction to the storage report was somewhat surprising. "It's difficult to think that that [injection] number was that low," especially given that storage stocks "are still well above the five-year average," he said.

De Pasquale noted that the relatively low injection may not be an indication of weak gas supplies but rather a function of storage levels being so high. "As storage gets full, it gets more difficult to cycle [gas] in," he said.

According to analyst Thomas Driscoll of Lehman Brothers in New York, "the injection rates of the past five weeks indicate that the gas market has gone from being balanced ... to about 2.2 Bcf/day oversupplied," Driscoll said. As a result, "lower prices may be required to correct the oversupply."

Driscoll noted that the National Oceanic and Atmospheric Administration's winter forecasts are calling for warmer-than-normal weather in the West, which "should more than offset cooler-than-normal temperatures forecast in the South/Southeast." If that forecast holds, weather-related demand this winter should be "about 150 to 200 Bcf greater than last year, and about equal to normal."

EIA reported injections for last week of 14 Bcf in the east region, to 1.894 Tcf (1.847 Tcf a year ago), 4 Bcf in the west region, to 422 Bcf (396 Bcf a year ago), and 8 Bcf in the producing region, to 933 Bcf (878 Bcf a year ago).

In the east, stocks are now 62 Bcf above the five-year average, while stocks are 46 Bcf above the five-year average in the west and 101 Bcf above in the producing region.

In the same week a year ago, 55 Bcf was injected to raise stocks to 3.121 Tcf, according to EIA's figures. Two years ago, 11 Bcf was injected to raise storage to 3.172 Tcf.

EIA also announced changes to its storage reporting schedule due to the upcoming Veterans' Day and Thanksgiving holidays. The storage report for the week ending Nov. 5 will be released on Wednesday, Nov. 10, while the report for the week ending Nov. 19 will be released on Wednesday, Nov. 24. MT

NYMEX Henry Hub gas futures contract, Oct 28

	Settlement	High	Low	+/-	Volume*
December, 2004	8.684	9.200	8.620	-9.8	21544
Jan., 2005	9.317	9.800	9.260	-11.8	8936
February	9.352	9.750	9.250	-11.8	3216
March	8.872	9.300	8.820	-12.8	4633
April	7.472	7.610	7.420	-7.8	2255
May	7.122	7.250	7.100	-7.8	669
June	7.144	7.250	7.140	-7.8	279
July	7.172	7.280	7.150	-7.8	390
August	7.192	7.300	7.150	-7.8	308
September	7.157	7.260	7.190	-7.3	209
October	7.187	7.290	7.180	-7.3	272
November	7.522	7.585	7.530	-6.3	242
December	7.827	7.880	7.830	-5.8	475
Jan., 2006	8.067	8.120	8.120	-5.3	529
February	8.047	8.070	8.050	-5.3	455
March	7.787	7.840	7.840	-5.3	786
April	6.627	6.675	6.675	-5.3	60
May	6.412	6.412	6.412	-5.3	86
June	6.437	6.437	6.437	-5.3	7
July	6.447	6.530	6.530	-6.3	7
August	6.462	6.462	6.462	-6.3	10
September	6.432	6.460	6.460	-6.3	9
October	6.467	6.500	6.500	-6.3	7
November	6.797	6.797	6.797	-6.3	7
December	7.087	7.180	7.150	-6.3	9
Jan. 2007	7.312	7.312	7.312	-6.8	427
February	7.287	7.287	7.287	-6.8	402
March	7.062	7.062	7.062	-6.8	177
April	6.062	6.062	6.062	-6.8	3
May	5.832	5.832	5.832	-6.8	3
June	5.847	5.847	5.847	-6.8	3
July	5.857	5.935	5.935	-7.8	3
August	5.872	5.960	5.960	-8.8	3
September	5.837	5.837	5.837	-8.8	3
October	5.862	5.832	5.832	-9.3	3
November	6.202	6.202	6.202	+9.3	3
Volume of contracts (official*)					**46,468**

Front-months open interest Wednesday:
Dec, 16,847 ; Jan, 70,167 ; Feb, 47,102
Total open interest Wednesday: n/a

NYMEX Henry Hub options closings, Oct 28

Strike	Calls-Settle			Puts-Settle		
Price	Dec.	Jan.	Feb.	Dec.	Jan.	Feb.
8.60	63.8¢	126.0¢	140.9¢	55.4¢	54.5¢	66.0¢
8.65	61.4¢	123.2¢	138.3¢	58.0¢	56.7¢	68.4¢
8.70	59.2¢	120.4¢	135.7¢	60.8¢	58.9¢	70.8¢
8.75	57.3¢	117.7¢	133.2¢	63.8¢	61.2¢	73.2¢
8.80	55.2¢	115.2¢	130.7¢	66.8¢	63.6¢	75.7¢
8.85	53.3¢	112.6¢	128.2¢	69.9¢	66.0¢	78.2¢
8.90	51.4¢	110.0¢	125.9¢	73.0¢	68.4¢	80.8¢
8.95	49.2¢	107.5¢	123.5¢	76.2¢	70.9¢	83.4¢
9.00	47.9¢	105.1¢	121.2¢	79.5¢	73.5¢	86.1¢

Platts oil prices, Oct 28

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid	35.50-35.75	5.67
3% Resid	32.00-32.50	5.13
Crude spot		
WTI (Dec)	50.77-50.79	8.08
New York spot		
No.2	60.77-60.86	10.44
0.3% Resid HP	41.50-41.75	6.62
0.3% Resid LP	45.25-45.75	7.24
0.7% Resid	36.75-37.00	5.87
1% Resid HP	34.00-34.25	5.43

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2003 Hedging Results

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 3
COMPANY/ F.P.&L.
WITNESS: G. Yupp (GJY-1)
DATE: 11-08-04

GJY-1
Docket No. 040001-EI
FPL Witness: Gerard Yupp
Pages 1 – 39
April 1, 2004

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS				
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	SAVINGS	GAINS
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
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	PHYSICAL POWER OPTION PREMIUMS				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
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	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

		ELECTRICITY			
		VOLUME			
PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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	SWING SWAPS				
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	BROKER FEES				

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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
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	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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APPENDIX I

FUEL COST RECOVERY

GJY-2

DOCKET NO. 040001-EI

EXHIBIT_____

PAGES 1-6

SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 4
COMPANY/ F.P.+L.
WITNESS. G. Yupp (GJY-2)
DATE: 11-08-04

APPENDIX 1

FUEL COST RECOVERY

TABLE OF CONTENTS

PAGE	DESCRIPTION	SPONSOR
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3	Projected Availability of Natural Gas	G. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. Yupp
5,6	2005 Risk Management Plan	G. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2005

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	33.00	32.38	31.68	31.47	31.87	32.16	32.27	32.24	31.79	31.01	30.61	29.99
1.0% Sulfur Grade ($/mmBtu)	5.16	5.06	4.95	4.92	4.98	5.03	5.04	5.04	4.97	4.85	4.78	4.69

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	52.11	51.89	50.89	49.49	48.17	47.23	46.99	47.08	47.34	47.60	47.86	48.12
0.05% Sulfur Grade ($/mmBtu)	8.94	8.90	8.73	8.49	8.26	8.10	8.06	8.08	8.12	8.16	8.21	8.25

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	760,000	760,000	760,000	859,000	894,000	894,000	894,000	894,000	894,000	859,000	760,000	760,000
Firm Gulfstream (mmBtu/Day)	-	-	-	-	-	350,000	350,000	350,000	350,000	350,000	350,000	350,000
Non-Firm FGT (mmBtu/Day)	150,000	150,000	150,000	110,000	50,000	50,000	50,000	50,000	50,000	110,000	150,000	150,000
Non-Firm Gulfstream (mmBtu/Day)	463,000	463,000	463,000	438,000	413,000	413,000	413,000	413,000	413,000	438,000	463,000	463,000
Total Projected Daily Availability (mmBtu/Day)	1,373,000	1,373,000	1,373,000	1,407,000	1,357,000	1,707,000	1,707,000	1,707,000	1,707,000	1,757,000	1,723,000	1,723,000

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	7.10	7.05	6.88	6.25	6.08	6.10	6.14	6.15	6.12	6.13	6.29	6.47
Firm Gulfstream ($/mmBtu)	-	-	-	-	-	6.06	6.10	6.11	6.07	6.09	6.24	6.42
Non-Firm FGT ($/mmBtu)	7.25	7.21	7.03	6.42	6.31	6.33	6.37	6.38	6.35	6.30	6.44	6.62
Non-Firm Gulfstream ($/mmBtu)	7.47	7.42	7.25	6.65	6.69	6.71	6.75	6.76	6.73	6.59	6.75	6.93

Solid Fuel	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
SJRPP ($/mmBtu)	2.03	2.03	2.03	2.03	2.03	2.02	2.02	2.02	2.02	2.02	2.02	2.02

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES
Cape Canaveral 1	1.4	3.6	15.3	02/05/05 - 04/01/05			
Cape Canaveral 2	1.3	3.4	11.5	10/15/05 - 11/25/05			
Cutler 5	1.0	1.2	8.2	10/22/05 - 11/20/05			
Cutler 6	1.3	1.7	11.5	10/22/05 - 12/02/05			
Lauderdale 4	0.9	4.2	3.3	03/19/05 - 03/30/05			
Lauderdale 5	0.9	4.2	19.7	09/24/05 - 12/04/05			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	1.0	4.2	1.6	02/12/05 - 02/23/05 **	01/29/05 - 02/09/05 **	01/15/05 - 01/26/05 **	
Ft. Myers 3	1.1	1.7	1.6	02/26/05 - 03/03/05 **	03/05/05 - 03/10/05 **		
Ft. Myers GTs	0.3	1.3	2.1	03/01/05 - 03/28/05 **	04/01/05 - 04/28/05 **	02/01/05 - 02/28/05 **	03/01/05 - 03/07/05 **
Manatee 1	1.1	3.3	20.5	09/17/05 - 11/30/05			
Manatee 2	1.0	3.2	0.0	NONE			
Manatee 3	1.5	0.6	0.0	NONE			
Martin 1	0.8	2.5	17.3	01/29/05 - 04/01/05			
Martin 2	0.9	2.8	0.0	NONE			
Martin 3	1.0	3.9	0.8	03/12/05 - 03/17/05 **			
Martin 4	1.0	4.3	2.5	02/12/05 - 02/17/05 **	03/19/05 - 03/30/05 **		
Martin 8 CC	1.5	0.6	0.0	NONE			
Port Everglades 1	1.8	2.4	15.3	10/01/05 - 11/25/05			
Port Everglades 2	1.9	2.4	22.5	02/26/05 - 05/18/05			
Port Everglades 3	1.3	3.4	5.8	02/05/05 - 02/25/05			
Port Everglades 4	1.2	3.2	0.0	NONE			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	1.0	3.2	9.6	03/12/05 - 04/15/05 **	10/15/05 - 11/18/05 **		
Putnam 2	1.0	3.2	6.8	04/23/05 - 05/27/05 **	04/30/05 - 05/14/05 **		
Riviera 3	2.4	3.4	7.7	03/12/05 - 04/08/05			
Riviera 4	2.8	3.9	8.2	10/08/05 - 11/06/05			
Sanford 3	1.8	2.2	5.8	03/12/05 - 04/01/05			
Sanford 4 CC	1.0	3.3	0.5	02/05/05 - 02/12/05 **			
Sanford 5 CC	1.0	3.7	2.7	05/28/05 - 06/06/05 **	05/14/05 - 05/23/05 **	09/03/05 - 09/12/05 **	06/11/05 - 06/20/05 **
Turkey Point 1	1.4	3.6	0.0	NONE			
Turkey Point 2	1.4	3.6	20.5	02/26/05 - 05/11/05			
Turkey Point 3	1.3	1.3	0.0	NONE			
Turkey Point 4	1.0	1.0	17.8	04/09/05 - 06/13/05			
St. Lucie 1	1.0	1.0	16.4	10/03/05 - 12/02/05			
St. Lucie 2	1.3	1.3	0.0	NONE			
St. Johns River Power P:	1.8	4.0	16.2	02/27/05 - 04/26/05			
St. Johns River Power P:	2.0	4.4	0.0	NONE			
Scherer 4	1.8	4.0	0.0	NONE			

** Partial Planned Outage

2005 Risk Management Plan

1. Identify overall quantitative and qualitative risk management objectives.
   A. FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to achieve the goals of fuel price stability (volatility minimization), to potentially achieve fuel cost minimization, and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

      FPL plans to hedge a percentage of its residual fuel oil and natural gas purchases with a combination of fixed price transactions and options. Additionally, FPL plans to extend its hedging program up to two years beyond the next recovery period. FPL believes that hedging up to three years (next recovery period and an additional two years) into the future will help further achieve the goal of fuel price stability. FPL will approach hedging into the extended period cautiously, similar to its initial approach to implementing its expanded hedging program.

3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.
   A. The potential risks that FPL encounters with its fuel procurement are supplier credit, fuel supply and transportation availability, product quality, delivery timing, weather, environmental and supplier failure to deliver. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee for review and approval. Approval is given to remain within specified VaR limits. These VaR limits are specified in FPL's policies and procedures that were filed on a confidential basis with the Commission.

4. Describe the utility's oversight of its fuel procurement activities.
   A. The utility has a separate and independent middle office risk management department that provides oversight of fuel procurement activities at the deal level. In addition, an executive-level, Exposure Management Committee meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.
   A. Please see response to No. 4.

6. Describe the utility's corporate risk policy regarding fuel procurement activities.
   A. The utility has a written policy and procedures that define VaR, stop -loss, and duration limits for all forward activity by portfolio. FPL's policies and procedures were filed on a confidential basis with the Commission. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities.
   A. Please see response to No. 6.

8. Describe the utility's strategy to fulfill its risk management objectives.
   A. Please see response to No. 1.

9. Verify that the utility has sufficient policies and procedures to implement its strategy.
   A. Please see response to No. 6.

13. Describe the utility's reporting system for fuel procurement activities.
   A. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities.
   A. Please see response to No. 13.

15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.
   A. FPL does not believe that there are any such limitations currently.

APPENDIX I

FUEL COST RECOVERY

TRUE UP CALCULATION

KMD-1
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
February 23, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 5
COMPANY/ FP+L
WITNESS. K.M. Dubin (KMD-1)
DATE: 11-08-04

1

APPENDIX I

FUEL COST RECOVERY

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4 - 5	CALCULATION OF FINAL TRUE UP AMOUNT
6	CALCULATION OF FINAL TRUE UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2003

1	End of Period True-up for the period January through December 2003 (from page 4, lines D7 & D8)	$ (302,921,183)
2	Less - Estimated/Actual True-up for the same period *	$ (344,729,859)
3	Net Final True-up for the period January through December 2003	$ 41,808,676

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-03-1461-FOF-EI dated December 22, 2003

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(1) JAN	(2) FEB	(3) MAR	(4) APR	(5) MAY	(6) JUN
A		**Fuel Costs & Net Power Transactions**						
1	a	Fuel Cost of System Net Generation	$ 202,082,274	$ 166,332,573	$ 338,352,856	$ 220,910,699	$ 290,580,370	$ 301,507,670
	b	Incremental Hedging Costs	38,985	(72,347)	80,832	37,832	25,080	64,444
	c	Nuclear Fuel Disposal Costs	2,045,325	1,810,224	1,585,058	1,830,109	1,438,413	1,705,778
	d	Coal Cars Depreciation & Return	280,827	279,094	277,362	275,629	273,896	272,164
	e	Gas Pipelines Depreciation & Return	179,661	178,205	169,743	168,535	170,561	169,139
	f	DOE D&D Fund Payment	0	0	0	0	0	0
2	a	Fuel Cost of Power Sold (Per A6)	(12,579,178)	(10,953,013)	(2,393,727)	(4,860,362)	(2,233,044)	(3,762,281)
	b	Revenues from Off-System Sales	(4,563,079)	(2,636,240)	(647,973)	(1,097,584)	(463,000)	(637,885)
3	a	Fuel Cost of Purchased Power (Per A7)	20,296,416	12,949,526	26,342,605	22,880,054	28,117,567	24,599,036
	b	Energy Payments to Qualifying Facilities (Per A8)	11,897,821	12,098,222	10,942,372	8,250,698	12,980,622	12,252,734
	c	Cypress Settlement Payment	0	0	0	0	255,797	0
	d	Okeelanta Settlement Amortization including interest	818,207	816,772	814,626	812,971	812,626	809,227
4		Energy Cost of Economy Purchases (Per A9)	2,690,456	5,403,637	9,253,845	6,437,812	7,503,345	9,642,332
5		Total Fuel Costs & Net Power Transactions	$ 223,187,714	$ 186,206,654	$ 384,777,599	$ 255,646,393	$ 339,462,234	$ 346,622,358
6		**Adjustments to Fuel Cost**						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,649,558)	(2,656,228)	(2,619,112)	(4,890,322)	(3,333,364)	(3,919,200)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(109,305)	(104,038)	(106,100)	(64,303)	(73,782)	(1,513)
	c	Inventory Adjustments	(97,396)	(25,202)	(70,714)	(51,017)	67,936	(1,124,954)
	d	Non Recoverable Oil/Tank Bottoms	0	60,265	0	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
B		**kWh Sales**						
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	7,569,038,419	7,463,818,224	7,510,229,964	7,396,486,620	7,999,797,862	9,047,332,704
2		Sale for Resale (excluding FKEC & CKW)	35,312,711	39,847,223	39,632,175	45,981,820	46,122,096	42,551,013
3		Sub-Total Sales (excluding FKEC & CKW)	7,604,351,130	7,503,665,447	7,549,862,139	7,442,468,440	8,045,919,958	9,089,883,717
6		**Jurisdictional % of Total Sales (B1/B3)**	99.53562%	99.46896%	99.47506%	99.38217%	99.42676%	99.53189%
C		**True-up Calculation**						
1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 202,273,176	$ 200,127,330	$ 201,471,500	$ 228,902,315	$ 251,666,698	$ 284,778,187
2		**Fuel Adjustment Revenues Not Applicable to Period**						
	a 1	Blank Line						
	a 2	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)
	a 3	2002 Final True-up Refunded per Order PSC-03-0000-AS-EI	0	0	0	(8,051,908)	(8,051,908)	(8,051,908)
	b	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)
	c	Oil Backout Revenues, Net of revenue taxes	(2)	(2)	(25)	(0)	(0)	(2)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 201,107,640	$ 198,961,795	$ 200,305,941	$ 219,684,873	$ 242,449,256	$ 275,560,743
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	(43,241)	(46,853)	33,420	95,378	(28,433)	4,846
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	220,374,695	183,528,305	381,948,254	250,545,373	336,151,456	341,571,845
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.53562 %	99.46896 %	99.47506 %	99.38217 %	99.42676 %	99.53189 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 219,415,561	$ 182,596,295	$ 380,162,847	$ 249,214,815	$ 334,359,838	$ 340,144,346
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (18,307,921)	$ 16,365,500	$ (179,856,906)	$ (29,529,943)	$ (91,910,582)	$ (64,583,603)
8		Interest Provision for the Month (Line D10)	(94,270)	(93,296)	(172,231)	(266,978)	(322,706)	(361,539)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(24,862,663)	(8,003,144)	(187,444,965)	(208,602,661)	(292,196,725)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
10	a	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316
	b	2002 Final True-up Collected/(Refunded) This Period	0	0	0	8,051,908	8,051,908	8,051,908
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (97,329,839)	$ (80,470,320)	$ (259,912,141)	$ (281,069,837)	$ (364,663,901)	$ (420,969,820)

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.

(b) Generation Performance Incentive Factor is ((87,049,431) x 98.4280%) - See Order No. PSC-01-1741-FOF-EI.

(c) Per Estimated Schedule E-2, filed November 4, 2002.

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(7) JUL	(8) AUG	(9) SEP	(10) OCT	(11) NOV	(12) DEC	(13) TOTAL PERIOD
A		**Fuel Costs & Net Power Transactions**							
1	a	Fuel Cost of System Net Generation	$ 305,103,626	$ 270,721,136	$ 274,410,601	$ 266,663,492	$ 205,477,717	$ 184,750,020	$ 3,026,893,034
	b	Incremental Hedging Costs	23,168	57,164	30,721	22,522	32,540	26,134	367,076
	c	Nuclear Fuel Disposal Costs	1,990,036	2,048,395	2,044,636	1,592,645	1,946,203	1,830,992	21,867,814
	d	Coal Cars Depreciation & Return	270,431	268,699	266,966	265,233	263,501	261,768	3,255,570
	e	Gas Pipelines Depreciation & Return	167,718	166,296	164,874	163,452	162,031	160,609	2,020,823
	f	DOE D&D Fund Payment	0	0	0	0	6,077,275	0	6,077,275
2	a	Fuel Cost of Power Sold (Per A6)	(2,894,541)	(3,528,375)	(3,455,577)	(1,963,701)	(6,052,220)	(17,155,546)	(71,831,565)
	b	Revenues from Off-System Sales	(341,263)	(528,348)	(543,259)	(339,373)	(1,609,471)	(4,420,173)	(17,827,648)
3	a	Fuel Cost of Purchased Power (Per A7)	28,333,960	25,850,471	26,386,610	23,797,923	18,969,882	13,713,574	272,237,624
	b	Energy Payments to Qualifying Facilities (Per A8)	13,492,687	13,448,483	13,179,596	9,259,954	10,341,868	12,627,352	140,772,409
	c	Cypress Settlement Payment	0	0	0	0	0	0	255,797
	d	Okeelanta Settlement Amortization including interest	806,355	806,478	805,922	805,109	803,694	803,148	9,715,135
4		Energy Cost of Economy Purchases (Per A9)	12,520,952	11,098,073	14,380,869	12,759,606	11,765,946	5,752,084	109,208,957
5		Total Fuel Costs & Net Power Transactions	$ 359,473,130	$ 320,408,472	$ 327,671,959	$ 313,026,862	$ 248,178,965	$ 198,349,961	$ 3,503,012,301
6		**Adjustments to Fuel Cost**							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,934,201)	(4,155,922)	(3,808,697)	(3,644,128)	(3,604,089)	(2,771,474)	(41,986,294)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	5,786	8,575	10,393	(4,138)	(4,027)	(13,006)	(455,459)
	c	Inventory Adjustments	77,271	259,042	45,730	(50,755)	(57,964)	(43,201)	(1,071,224)
	d	Non Recoverable Oil/Tank Bottoms	0	0	0	0	0	0	60,265
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 355,621,985	$ 316,520,167	$ 323,919,384	$ 309,327,842	$ 244,512,884	$ 195,522,280	$ 3,459,559,589
B		**kWh Sales**							
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	9,332,603,999	9,223,379,666	9,347,439,851	8,815,192,252	8,092,460,610	7,703,539,787	99,501,319,958
2		Sale for Resale (excluding FKEC & CKW)	39,109,282	42,889,072	40,994,892	43,068,044	37,996,734	39,111,657	492,616,719
3		Sub-Total Sales (excluding FKEC & CKW)	9,371,713,281	9,266,268,738	9,388,434,743	8,858,260,296	8,130,457,344	7,742,651,444	99,993,936,677
6		**Jurisdictional % of Total Sales (B1/B3)**	99.58269%	99.53715%	99.56335%	99.51381%	99.53266%	99.49485%	99.50735%
C		**True-up Calculation**							
1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 293,881,101	$ 330,616,662	$ 340,593,218	$ 321,452,663	$ 294,979,143	$ 280,548,357	$ 3,231,290,350
2		**Fuel Adjustment Revenues Not Applicable to Period**							
	a 1	Blank Line							0.00
	a 2	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(7,047,788)
	a 3	2002 Final True-up Refunded per Order PSC-03-0000-AS-EI	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(72,467,176)
	b	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(6,938,614)
	c	Oil Backout Revenues, Net of revenue taxes	2	(1)	4	0	(2)	0	(28)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 284,663,661	$ 321,399,219	$ 331,375,780	$ 312,235,221	$ 285,761,700	$ 271,330,915	$ 3,144,836,744
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 355,621,985	$ 316,520,167	$ 323,919,384	$ 309,327,842	$ 244,512,884	$ 195,522,280	$ 3,459,559,589
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	37,384	(9,429)	29,218	90,664	(3,444)	20,537	180,048
	d	D&D Fund Payments -100% Retail	0	0	0	0	6,077,275	0	6,077,275
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	355,584,601	316,529,596	323,890,166	309,237,178	238,439,054	195,501,743	3,453,302,266
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.58269 %	99.53715 %	99.56335 %	99.51381 %	99.53266 %	99.49485 %	99.50735 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 354,311,605	$ 315,209,491	$ 322,663,131	$ 307,975,151	$ 243,514,853	$ 194,630,015	$ 3,444,197,949
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (69,647,944)	$ 6,189,728	$ 8,712,649	$ 4,260,070	$ 42,246,847	$ 76,700,900	$ (299,361,205)
8		Interest Provision for the Month (Line D10)	(385,649)	(417,576)	(405,679)	(390,854)	(352,832)	(296,367)	(3,559,977)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(348,502,644)	(409,897,012)	(395,485,636)	(378,539,442)	(366,031,003)	(315,497,764)	(7,047,788)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
10	a	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316	7,047,788
	b	2002 Final True-up Collected/(Refunded) This Period	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	72,467,176
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (482,364,188)	$ (467,952,812)	$ (451,006,618)	$ (438,498,179)	$ (387,964,940)	$ (302,921,183)	$ (302,921,183)

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.

(b) Generation Performance Incentive Factor is ((57,849,431) x 90.4280%) - See Order No. PSC-02-1761-POF-EI.

(c) Per Estimated Schedule E-2, filed November 4, 2002.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs ESTIMATED/ACTUAL
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	**Fuel Costs & Net Power Transactions**				
1	a Fuel Cost of System Net Generation	$ 3,026,893,034	$ 3,098,365,746	$ (71,472,712)	(2.3) %
	b Incremental Hedging Implementation Costs	367,076	385,994	(18,918)	(4.9) %
	c Nuclear Fuel Disposal Costs	21,867,814	21,908,055	(40,241)	(0.2) %
	d Coal Cars Depreciation & Return	3,255,570	3,255,570	0	0.0 %
	e Gas Pipelines Depreciation & Return	2,020,823	2,020,823	0	0.0 %
	f DOE D&D Fund Payment	6,077,275	6,475,000	(397,725)	(6.1) %
2	a Fuel Cost of Power Sold (Per A6)	(71,831,565)	(78,009,460)	6,177,895	(7.9) %
	b Revenues from Off-System Sales	(17,827,648)	(13,091,111)	(4,736,537)	36.2 %
3	a Fuel Cost of Purchased Power (Per A7)	272,237,624	253,413,971	18,823,653	7.4 %
	b Energy Payments to Qualifying Facilities (Per A8)	140,772,409	143,691,143	(2,918,734)	(2.0) %
	c Cypress Settlement Payment	255,797	255,797	0	0.0 %
	d Okeelanta Settlement Amortization including interest	9,715,135	9,708,785	6,350	0.1 %
4	Energy Cost of Economy Purchases (Per A9)	109,208,957	74,936,176	34,272,781	45.7 %
5	Total Fuel Costs & Net Power Transactions	$ 3,503,012,301	$ 3,523,316,489	$ (20,304,188)	(0.6) %
6	**Adjustments to Fuel Cost**				
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (41,986,294)	$ (37,389,545)	$ (4,596,749)	12.3 %
	b Reactive and Voltage Control Fuel Revenue	(455,459)	(459,042)	3,583	(0.8) %
	c Inventory Adjustments	(1,071,224)	(1,301,346)	230,122	(17.7) %
	d Non Recoverable Oil/Tank Bottoms	60,265	60,265	0	0.0 %
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 3,459,559,589	$ 3,484,226,823	$ (24,667,232)	(0.7) %
B 1	Jurisdictional kWh Sales	99,501,319,958	98,853,280,793	648,039,165	0.7 %
2	Sale for Resale	492,616,719	454,992,038	37,624,681	8.3 %
3	Total Sales (Excluding RTP Incremental)	99,993,936,677	99,308,272,831	685,663,846	0.7 %
4	Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
C	**True-up Calculation**				
1	Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 3,231,290,350	3,215,151,449	$ 16,138,901	0.5 %
2	**Fuel Adjustment Revenues Not Applicable to Period**				
	a 1 Prior Period True-up (Collected)/Refunded This Period	(7,047,788)	(7,047,788)	0	0.0 %
	a 2 2002 Final True-up Refunded per Order PSC-03-0381-PCO-EI	(72,467,176)	(72,467,176)	0	0.0 %
	b GPIF, Net of Revenue Taxes (b)	(6,938,614)	(6,938,614)	0	0.0 %
	c Oil Backout Revenues, Net of revenue taxes	(28)	(31)	3	(10.7) %
3	Jurisdictional Fuel Revenues Applicable to Period	$ 3,144,836,744	$ 3,128,697,839	$ 16,138,905	0.5 %
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 3,459,559,589	$ 3,484,226,823	(24,667,234)	(0.7) %
	b Nuclear Fuel Expense - 100% Retail	-	-	0	N/A
	c RTP Incremental Fuel -100% Retail	180,048	15,118	164,930	1090.9 %
	d D&D Fund Payments -100% Retail (Line A 1 e)	6,077,275	6,475,000	(397,725)	(6.1) %
	e Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	3,453,302,266	3,477,736,705	(24,434,439)	(0.7) %
5	Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions	$ 3,444,197,949	$ 3,469,917,608	$ (25,719,659)	(0.7) %
7	True-up Provision for the Period- Over/(Under) Recovery (Line C3 - Line C6)	$ (299,361,205)	$ (341,219,769)	41,858,564	(12.3) %
8	Interest Provision for the Period	(3,559,977)	(3,510,090)	(49,888)	1.4 %
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(7,047,788)	0	0.0 %
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	0	0.0 %
10	a Prior Period True-up Collected/(Refunded) This Period	7,047,788	7,047,788	0	0.0 %
	b 2002 Final True-up Collected/(Refunded) This Period	72,467,176	72,467,176	(0)	0.0 %
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (302,921,183)	$ (344,729,859)	$ 41,808,676	(12.1) %

NOTES **(a) Per Estimated/Actual, Schedule E1b, filed August 12, 2003.**

(b) Generation Performance Incentive Factor is (($7,049,431) x 98.4280%) - See Order No. PSC-02-1761-FOF-EI.

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
February 23, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 6
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-2)
DATE: 11-08-04

APPENDIX II

CAPACITY COST RECOVERY

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2003

1.	End of Period True-up for the period January through December 2003 (from page 5, lines 17 & 18)	$ 8,998,342
2.	Less - Estimated/Actual True-up for the same period *	16,048,425
3.	Net True-up for the period January through December 2003	$ (7,050,083)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-03-1461-FOF-EI dated December 22, 2003

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.		(1) JAN 2003	(2) FEB 2003	(3) MAR 2003	(4) APR 2003	(5) MAY 2003	(6) JUN 2003
1.	Payments to Non-cogenerators (UPS & SJRPP)	$15,596,426	$15,990,408	$14,684,403	$15,153,064	$14,649,614	$15,005,398
2.	Short Term Capacity Payments	6,245,451	6,245,451	4,361,584	4,490,250	6,995,796	15,128,009
3.	Payments to Cogenerators (QF's)	27,481,162	28,207,963	28,961,670	29,873,286	34,695,552	28,990,956
4a.	SJRPP Suspension Accrual	586,656	586,656	586,656	586,656	586,656	586,656
4b.	Return on SJRPP Suspension Liability	(229,653)	(235,428)	(241,204)	(246,979)	(252,755)	(258,531)
5a.	Cypress Settlement (Capacity)	0	0	0	0	353,244	0
5b.	Okeelanta Settlement (Capacity)	3,078,016	3,072,620	3,064,546	3,058,320	3,057,020	3,044,234
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	113,771	832,709	1,151,391	787,976	769,376	709,694
7.	Tranmission of Electricity by Others	708,540	726,582	967,321	1,113,810	744,916	497,782
8.	Transmission Revenues from Capacity Sales	(853,648)	(676,765)	(153,736)	(226,606)	(243,744)	(329,412)
9.	Total (Lines 1 through 8)	$ 52,726,720	$ 54,750,196	$ 53,382,631	$ 54,589,777	$ 61,355,676	$ 63,374,786
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%
11.	Jurisdictional Capacity Charges	52,208,638	54,212,232	52,858,104	54,053,389	60,752,807	62,752,078
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 47,463,172	$ 49,466,766	$ 48,112,638	$ 49,307,923	$ 56,007,341	$ 58,006,612
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 45,289,301	$ 44,889,661	$ 44,494,357	$ 44,357,710	$ 47,550,317	$ 52,878,607
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 48,723,919	$ 48,324,279	$ 47,928,975	$ 47,792,328	$ 50,984,935	$ 56,313,225
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	1,260,747	(1,142,487)	(183,663)	(1,515,596)	(5,022,407)	(1,693,387)
18.	Interest Provision for Month	56,326	51,960	46,008	40,687	34,539	25,582
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	41,215,416	39,097,870	34,572,726	31,000,453	26,090,927	17,668,441
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 51,774,593	$ 47,249,449	$ 43,677,176	$ 38,767,650	$ 30,345,164	$ 25,242,741

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffmann's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.		(7) JUL 2003	(8) AUG 2003	(9) SEP 2003	(10) OCT 2003	(11) NOV 2003	(12) DEC 2003	(13) TOTAL
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,208,389	$14,803,677	$14,029,336	$16,232,538	$15,455,862	$14,017,230	$181,826,345
2.	Short Term Capacity Payments	15,063,510	14,822,310	8,447,380	3,758,876	3,873,799	6,156,400	95,588,816
3.	Payments to Cogenerators (QF's)	28,863,092	28,838,119	28,826,788	28,844,161	29,156,890	29,110,184	351,849,823
4a.	SJRPP Suspension Accrual	586,656	586,656	586,656	586,656	586,656	586,656	7,039,872
4b.	Return on SJRPP Suspension Liability	(264,306)	(270,082)	(275,857)	(281,633)	(287,409)	(293,184)	(3,137,021)
5a.	Cypress Settlement (Capacity)	0	0	0	0	0	0	353,244
5b.	Okeelanta Settlement (Capacity)	3,033,431	3,033,895	3,031,801	3,028,744	3,023,422	3,021,365	36,547,413
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	868,722	1,285,560	1,227,623	738.069	222,684	605,027	9,312,602
7.	Tranmission of Electricity by Others	476,575	512,334	454,678	531,831	489,636	606,800	7,830,805
8.	Transmission Revenues from Capacity Sales	(269,550)	(289,278)	(394,001)	(98,474)	(413,838)	(978,149)	(4,927,201)
9.	Total (Lines 1 through 8)	$64,566,518	$63,323,191	$55,934,404	$53,340,768	$52,107,702	$52,832,329	$ 682,284,698
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	N/A
11.	Jurisdictional Capacity Charges	63,932,101	62,700,990	55,384,803	52,816,652	51,595,702	52,313,209	675,580,705
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)
13.	Jurisdictional Capacity Charges Authorized	$59,186,635	$57,955,524	$50,639,337	$48,071,186	$46,850,236	$47,567,743	$ 618,635,113
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$54,379,742	$53,846,880	$54,260,963	$51,682,946	$47,641,729	$44,779,506	$ 586,051,718
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	41,215,416
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$57,814,360	$57,281,498	$57,695,581	$55,117,564	$51,076,347	$48,214,124	$ 627,267,134
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(1,372,275)	(674,026)	7,056,243	7,046,378	4,226,111	646,382	8,632,021
18.	Interest Provision for Month	19,509	16,178	16,053	19,172	20,523	19,784	366,321
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	12,566,018	7,778,634	3,686,168	7,323,847	10,954,778	11,766,794	41,215,416
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(41,215,416)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$20,455,357	$16,362,891	$20,000,570	$23,631,501	$24,443,517	$21,675,065	$ 21,675,065

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per R.L. Hoffman's Testim
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

Line No.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	Payments to Non-cogenerators (UPS & SJRPP)	$ 181,826,345	$ 174,307,675	$ 7,518,670	4.3 %
2	Short Term Capacity Payments	$ 95,588,816	94,397,361	1,191,455	1.3 %
3	Payments to Cogenerators (QF's)	351,849,823	350,923,536	926,287	0.3 %
4a	SJRPP Suspension Accrual	7,039,872	7,039,872	0	0.0 %
4b	Return Requirements on SJRPP Suspension Liability	(3,137,021)	(3,137,021)	0	(0.0) %
5a	Cypress Settlement (Capacity)	353,244	353,244	0	0.0 %
5b	Okeelanta Settlement (Capacity)	36,547,413	36,523,524	23,889	0.1 %
6	Incremental Plant Security Costs-Order No. PSC-02-1761	9,312,602	10,258,750	(946,148)	(9.2) %
7	Transmission of Electricity by Others	7,830,805	8,382,284	(551,479)	(6.6) %
8	Transmission Revenues from Capacity Sales	(4,927,201)	(5,179,411)	252,210	(4.9) %
9	Total (Lines 1 through 8)	$ 682,284,698	$ 673,869,814	$ 8,414,884	1.2 %
10	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
11	Jurisdictional Capacity Charges	$ 675,580,705	$ 667,248,505	$ 8,332,200	1.2 %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 618,635,113	$ 610,302,913	$ 8,332,200	1.4 %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 586,051,718	$ 584,746,334	$ 1,305,384	0.2 %
15	Prior Period True-up Provision	41,215,416	41,215,416	0	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 627,267,134	$ 625,961,750	$ 1,305,384	0.2 %
17	True-up Provision for Period - Over/(Under) Recovery (Line 16 - Line 13)	$ 8,632,021	$ 15,658,837	$ (7,026,816)	N/A
18	Interest Provision for Period	366,321	389,587	(23,266)	N/A
19	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	41,215,416	41,215,416	(0)	N/A
20	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	0	N/A
21	Prior Period True-up Provision - Collected/(Refunded) this Period	(41,215,416)	(41,215,416)	0	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 21,675,065	$ 28,725,147	$ (7,050,083)	(24.5) %

Notes:

(a) Per K. M. Dubin's Testimony Appendix II, Page 4, Docket No. 030001-EI, filed August 12, 2003.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

APPENDIX I

FUEL COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-3
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
August 10, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 7
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-3)
DATE: 11-08-04

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004
SIX MONTHS ACTUAL SIX MONTHS REVISED ESTIMATES

LINE NO.			(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A		**Fuel Costs & Net Power Transactions**						
	1	a Fuel Cost of System Net Generation	$ 184,452,314	$ 175,787,137	$ 214,008,305	$ 225,837,849	$ 273,633,221	$ 329,439,294
		b Incremental Hedging Costs	39,539	43,636	95,460	33,158	53,388	50,597
		c Nuclear Fuel Disposal Costs	2,101,960	1,950,911	1,944,426	1,523,704	1,860,877	1,983,248
		d Coal Cars Depreciation & Return	260,036	270,239	330,547	378,675	376,456	374,237
		e Gas Pipelines Depreciation & Return	159,187	157,765	156,343	154,922	153,500	152,078
		f DOE D&D Fund Payment	-	-	-	-	-	-
	2	a Fuel Cost of Power Sold (Per A6)	(11,421,993)	(11,341,688)	(11,522,125)	(11,512,453)	(9,166,845)	(7,610,577)
		b Gains from Off-System Sales	(3,487,436)	(2,828,818)	(2,150,944)	(2,193,430)	(1,561,821)	(784,437)
	3	a Fuel Cost of Purchased Power (Per A7)	15,140,887	14,698,590	14,110,542	17,432,844	17,161,636	33,206,788
		b Energy Payments to Qualifying Facilities (Per A8)	12,108,633	11,650,079	10,503,252	12,428,163	10,672,709	12,559,402
		c Okeelanta Settlement Amortization including interest	802,825	801,251	800,055	799,947	799,908	802,205
	4	Energy Cost of Economy Purchases (Per A9)	4,259,680	3,504,914	3,433,118	6,272,765	7,027,964	3,273,294
	5	Total Fuel Costs & Net Power Transactions	204,415,631	194,694,018	231,708,980	251,156,144	301,010,992	373,446,129
	6	**Adjustments to Fuel Cost**						
		a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,667,940)	(2,628,591)	(2,507,271)	(3,056,227)	(3,064,860)	(3,715,083)
		b Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(79,263)	(106,143)	(147,636)	4,907	33,674	(40,655)
		c Inventory Adjustments	(126,576)	(12,827)	(73,126)	34,959	(36,019)	223,329
		d Non Recoverable Oil/Tank Bottoms	-	-	-	(45,837)	-	-
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 201,541,853	$ 191,946,456	$ 228,980,948	$ 248,093,946	$ 297,943,787	$ 369,913,720
B		**kWh Sales**						
	1	Jurisdictional kWh Sales	7,668,715,414	7,175,175,525	7,034,440,332	6,799,137,180	7,644,908,043	9,270,486,870
	2	Sale for Resale (excluding FKEC & CKW)	48,691,074	45,861,710	39,221,146	43,391,707	42,455,919	38,691,036
	3	Sub-Total Sales (excluding FKEC & CKW)	7,717,406,488	7,221,037,235	7,073,661,478	6,842,528,887	7,687,363,962	9,309,177,906
	6	**Jurisdictional % of Total Sales (B1/B3)**	99.36907%	99.36489%	99.44553%	99.36585%	99.44772%	99.58438%
C		**True-up Calculation**						
	1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 281,915,788	$ 264,071,397	$ 258,908,817	$ 250,291,507	$ 281,575,254	$ 342,544,711
	2	**Fuel Adjustment Revenues Not Applicable to Period**						
		a Prior Period True-up (Collected)/Refunded This Period	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)
		b GPIF, Net of Revenue Taxes (a)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)
		c Oil Backout Revenues, Net of revenue taxes	(0)	0	(9)	0	0	(1)
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 252,577,273	$ 234,732,882	$ 229,570,293	$ 220,952,992	$ 252,236,738	$ 313,206,195
	4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 201,541,853	$ 191,946,456	$ 228,980,948	$ 248,093,946	$ 297,943,787	$ 369,913,720
		b Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
		c RTP Incremental Fuel -100% Retail	0	0	0	0	0	0
		d D&D Fund Payments -100% Retail	0	0	0	0	0	0
		e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	201,541,853	191,946,456	228,980,948	248,093,946	297,943,787	369,913,720
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.36907 %	99.36489 %	99.44553 %	99.36585 %	99.44772 %	99.58438 %
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00059(c)) +(Lines C4b,c,d)	$ 200,388,424	$ 190,839,915	$ 227,845,667	$ 246,666,105	$ 296,473,119	$ 368,593,627
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 52,188,849	$ 43,892,967	$ 1,724,626	$ (25,713,113)	$ (44,236,381)	$ (55,387,432)
	8	Interest Provision for the Month (Line D10)	(228,553)	(155,711)	(109,881)	(98,757)	(107,179)	(143,639)
	9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(344,729,859)	(264,042,075)	(191,577,330)	(161,235,097)	(158,319,479)	(173,935,550)
		b Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676
	10	Prior Period True-up Collected/(Refunded) This Period	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (222,233,399)	$ (149,768,654)	$ (119,426,421)	$ (116,510,803)	$ (132,126,874)	$ (158,930,457)

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004
SIX MONTHS ACTUAL SIX MONTHS REVISED ESTIMATES

LINE NO.		(7) REVISED EST. JUL	(8) REVISED EST. AUG	(9) REVISED EST. SEP	(10) REVISED EST. OCT	(11) REVISED EST. NOV	(12) REVISED EST. DEC	(13) TOTAL PERIOD
A	**Fuel Costs & Net Power Transactions**							
1	a Fuel Cost of System Net Generation	$ 328,158,233	$ 331,417,022	$ 323,993,606	$ 305,098,671	$ 258,860,614	$ 239,867,115	$ 3,190,553,382
	b Incremental Hedging Costs	34,945	34,945	34,945	34,945	48,775	34,945	539,278
	c Nuclear Fuel Disposal Costs	1,983,357	1,983,357	1,828,859	1,515,688	1,483,193	1,606,560	21,766,140
	d Coal Cars Depreciation & Return	372,017	369,798	367,579	365,359	363,140	360,921	4,189,004
	e Gas Pipelines Depreciation & Return	150,656	75,003	49,341	48,901	48,461	48,021	1,354,179
	f DOE D&D Fund Payment	-	-	-	-	6,671,000	-	6,671,000
2	a Fuel Cost of Power Sold (Per A6)	(7,516,774)	(8,052,651)	(7,885,260)	(7,353,729)	(10,176,498)	(13,080,892)	(116,641,485)
	b Gains from Off-System Sales	(891,900)	(935,800)	(555,650)	(407,450)	(436,000)	(759,000)	(16,992,686)
3	a Fuel Cost of Purchased Power (Per A7)	34,719,157	34,069,259	33,152,675	20,325,358	17,691,216	24,026,493	275,735,445
	b Energy Payments to Qualifying Facilities (Per A8)	13,322,000	13,300,000	12,983,000	13,616,000	11,104,000	13,563,000	147,810,238
	c Okeelanta Settlement Amortization including interest	798,469	797,800	797,132	796,463	795,795	795,126	9,586,975
4	Energy Cost of Economy Purchases (Per A9)	2,719,847	2,929,499	2,907,577	6,336,972	5,771,883	5,977,227	54,414,740
5	Total Fuel Costs & Net Power Transactions	373,850,007	375,988,232	367,673,804	340,377,179	292,225,579	272,439,516	3,578,986,211
6	**Adjustments to Fuel Cost**							
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,753,544)	(3,892,284)	(3,953,281)	(3,771,405)	(3,539,694)	(3,239,889)	(39,790,068)
	b Reactive and Voltage Control / Energy Imbalance Fuel Revenues							(335,114.86)
	c Inventory Adjustments							9,740.63
	d Non Recoverable Oil/Tank Bottoms							(45,837.17)
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 370,096,463	$ 372,095,948	$ 363,720,523	$ 336,605,775	$ 288,685,885	$ 269,199,628	$ 3,538,824,932
B	**kWh Sales**							
1	Jurisdictional kWh Sales	9,766,926,607	9,956,053,270	9,877,393,892	9,083,786,926	8,072,305,230	7,940,128,805	100,289,458,094
2	Sale for Resale (excluding FKEC & CKW)	48,561,368	50,429,142	51,331,964	49,729,793	44,385,501	40,270,148	543,020,508
3	Sub-Total Sales (excluding FKEC & CKW)	9,815,487,975	10,006,482,412	9,928,725,855	9,133,516,720	8,116,690,731	7,980,398,953	100,832,478,602
6	**Jurisdictional % of Total Sales (B1/B3)**	99.50526%	99.49604%	99.48300%	99.45552%	99.45316%	99.49539%	N/A
C	**True-up Calculation**							
1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 359,733,073	$ 366,698,941	$ 363,801,778	$ 334,571,838	$ 297,317,190	$ 292,448,899	$ 3,693,879,193
2	**Fuel Adjustment Revenues Not Applicable to Period**							
	a Prior Period True-up (Collected)/Refunded This Period	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(344,729,859)
	b GPIF, Net of Revenue Taxes (a)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(7,332,324)
	c Oil Backout Revenues, Net of revenue taxes	0	0	0	0	0	0	(10)
3	Jurisdictional Fuel Revenues Applicable to Period	$ 330,394,558	$ 337,360,425	$ 334,463,262	$ 305,233,323	$ 267,978,674	$ 263,110,384	$ 3,341,817,000
4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 370,096,463	$ 372,095,948	$ 363,720,523	$ 336,605,775	$ 288,685,885	$ 269,199,628	$ 3,538,824,932
b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0
c	RTP Incremental Fuel -100% Retail	0	0	0	0	0	0	0
d	D&D Fund Payments -100% Retail	0	0	0	0	6,671,000	0	6,671,000
e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	370,096,463	372,095,948	363,720,523	336,605,775	282,014,885	269,199,628	3,532,153,932
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.50526 %	99.49604 %	99.48300 %	99.45552 %	99.45316 %	99.49539 %	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00059(e)) +(Lines C4b,c,d)	$ 368,482,725	$ 370,439,164	$ 362,053,573	$ 334,970,540	$ 287,309,194	$ 267,999,246	$ 3,522,061,299
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (38,088,167)	$ (33,078,739)	$ (27,590,311)	$ (29,737,217)	$ (19,330,520)	$ (4,888,862)	$ (180,244,299)
8	Interest Provision for the Month (Line D10)	(181,330)	(189,129)	(191,120)	(191,261)	(186,825)	(168,615)	(1,952,000)
9 a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(200,739,133)	(210,281,141)	(214,821,521)	(213,875,464)	(215,076,454)	(205,866,310)	(344,729,859)
b	Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676
10	Prior Period True-up Collected/(Refunded) This Period	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	344,729,859
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (168,472,465)	$ (173,012,845)	$ (172,066,788)	$ (173,267,778)	$ (164,057,634)	$ (140,387,623)	$ (140,387,623)

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ESTIMATED/ACTUAL vs ORIGINAL PROJECTIONS
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

	LINE NO.			(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A			**Fuel Costs & Net Power Transactions**				
	1	a	Fuel Cost of System Net Generation	$ 3,190,553,382	$ 2,948,212,042	$ 242,341,340	8.2 %
		b	Incremental Hedging Costs	539,278	427,857	111,421	26.0 %
		c	Nuclear Fuel Disposal Costs	21,766,140	21,731,958	34,182	0.2 %
		d	Coal Cars Depreciation & Return	4,189,004	4,413,013	(224,009)	(5.1) %
		e	Gas Pipelines Depreciation & Return	1,354,179	1,816,407	(462,228)	(25.4) %
		f	DOE D&D Fund Payment	6,671,000	6,670,000	1,000	0.0 %
	2	a	Fuel Cost of Power Sold (Per A6)	(116,641,485)	(53,937,966)	(62,703,519)	116.3 %
		b	Gains from Off-System Sales	(16,992,686)	(7,048,624)	(9,944,062)	141.1 %
	3	a	Fuel Cost of Purchased Power (Per A7)	275,735,445	288,786,758	(13,051,313)	(4.5) %
		b	Energy Payments to Qualifying Facilities (Per A8)	147,810,238	148,266,648	(456,410)	(0.3) %
		c	Okeelanta Settlement Amortization including interest	9,586,975	9,578,625	8,350	0.1 %
	4		Energy Cost of Economy Purchases (Per A9)	54,414,740	52,338,486	2,076,254	4.0 %
	5		Total Fuel Costs & Net Power Transactions	$ 3,578,986,211	$ 3,421,255,204	$ 157,731,007	4.6 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (39,790,068)	$ (41,152,955)	$ 1,362,887	(3.3) %
		b	Reactive and Voltage Control Fuel Revenue	(335,115)		(335,115)	N/A
		c	Inventory Adjustments	9,741		9,741	N/A
		d	Non Recoverable Oil/Tank Bottoms	(45,837)		(45,837)	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 3,538,824,932	$ 3,380,102,249	$ 158,722,683	4.7 %
B			**Jurisdictional kWh Sales**				
	1		Jurisdictional kWh Sales	100,289,458,094	100,913,606,000	(624,147,906)	(0.6) %
	2		Sale for Resale (excluding FKEC & CKW)	543,020,508	519,832,000	23,188,508	4.5 %
	3		Sub-Total Sales (excluding FKEC & CKW)	100,832,478,602	101,433,438,000	(600,959,398)	(0.6) %
	4		**Jurisdictional % of Total Sales (B1/B3)**	N/A	N/A	N/A	N/A
			True-up Calculation				
C	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 3,693,879,193	3,716,163,293	$ (22,284,101)	(0.6) %
	2		**Fuel Adjustment Revenues Not Applicable to Period**				
		a 1	Prior Period True-up (Collected)/Refunded This Period	(344,729,859)	(344,729,859)	0	0.0 %
		b	GPIF, Net of Revenue Taxes (b)	(7,332,324)	(7,332,324)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes	(10)	0	(10)	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 3,341,817,000	$ 3,364,101,110	$ (22,284,101)	(0.7) %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 3,538,824,932	$ 3,380,102,249	$ 158,722,683	4.7 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	0	0	0	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 f)	6,671,000	6,670,000	1,000	0.0 %
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	3,532,153,932	3,373,432,249	158,721,683	4.7 %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 3,522,111,210	$ 3,364,101,110	$ 158,010,100	4.7 %
	7		True-up Provision for the Period Over/(Under) Recovery (Line C3 - Line C6)	$ (180,244,299)	$ 0	$ (180,244,299)	N/A
	8		Interest Provision for the Period	(1,952,000)	0	(1,952,000)	N/A
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(344,729,859)	(344,729,859)	0	0.0 %
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	0	41,808,676	N/A
	10		Prior Period True-up Collected/(Refunded) This Period	344,729,859	344,729,859	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through D10)	$ (140,387,623)	$ 0	$ (140,387,623)	N/A

NOTES

(a) **Per Original Projections approved by the Commission in Order No. PSC-1461-FOF-EI (December 22, 2003).**

(b) **Generation Performance Incentive Factor is (($7,449,429) x 98.4280%) - See Order No. PSC-03-1461-FOF-EI.**

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-4
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
August 10, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 8
COMPANY/ FP+L
WITNESS: K.M. Dubin (KMD-4)
DATE: 11-08-04

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

LINE NO.		(1) JAN 2004 ACTUAL	(2) FEB 2004 ACTUAL	(3) MAR 2004 ACTUAL	(4) APR 2004 ACTUAL	(5) MAY 2004 ACTUAL	(6) JUN 2004 ACTUAL
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$17,271,885	$16,715,070	$15,608,268	$15,512,596	$15,650,658	$16,010,555
2.	Short Term Capacity Payments	6,156,400	6,156,400	3,873,860	3,794,640	7,013,850	16,432,978
3.	Capacity Payments to Cogenerators (QFs)	29,618,332	29,384,726	29,454,264	30,078,378	30,398,617	30,479,099
4a.	SJRPP Suspension Accrual	422,797	422,797	422,797	422,797	422,797	422,797
4b.	Return Requirements on SJRPP Suspension Payments	(298,153)	(302,316)	(306,478)	(310,640)	(314,803)	(318,965)
5.	Okeelanta Settlement	3,020,150	3,014,230	3,009,732	3,009,323	3,009,176	3,017,819
6.	Incremental Plant Security Costs	562,344	654,189	1,001,012	865,299	1,269,330	2,948,484
7.	Transmission of Electricity by Others	817,671	808,943	807,484	649,195	611,848	798,578
8.	Transmission Revenues from Capacity Sales	(687,840)	(654,693)	(634,963)	(581,752)	(542,200)	(1,041,719)
9.	Total (Lines 1 through 8)	$ 56,883,586	$ 56,199,348	$ 53,235,976	$ 53,439,835	$ 57,519,274	$ 68,749,626
10.	Jurisdictional Separation Factor (a)	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%
11.	Jurisdictional Capacity Charges	56,225,448	55,549,127	52,620,041	52,821,541	56,853,782	67,954,199
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 51,479,982	$ 50,803,661	$ 47,874,575	$ 48,076,075	$ 52,108,316	$ 63,208,733
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 43,705,699	$ 41,526,132	$ 40,883,478	$ 39,699,773	$ 44,106,141	$ 52,885,350
15.	Prior Period True-up Provision	2,393,762	2,393,762	2,393,762	2,393,762	2,393,762	2,393,762
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 46,099,461	$ 43,919,894	$ 43,277,240	$ 42,093,535	$ 46,499,903	$ 55,279,112
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(5,380,521)	(6,883,767)	(4,597,335)	(5,982,541)	(5,608,412)	(7,929,622)
18.	Interest Provision for Month	15,490	7,770	940	(5,470)	(12,702)	(23,603)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	28,725,148	20,966,356	11,696,596	4,706,439	(3,675,334)	(11,690,209)
20.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 13,916,273	$ 4,646,513	$ (2,343,644)	$ (10,725,417)	$ (18,740,292)	$ (29,087,279)

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 12, 2003.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

LINE NO.		(7) JUL 2004 ESTIMATED	(8) AUG 2004 ESTIMATED	(9) SEP 2004 ESTIMATED	(10) OCT 2004 ESTIMATED	(11) NOV 2004 ESTIMATED	(12) DEC 2004 ESTIMATED	(13) TOTAL	LINE NO.
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$189,565,905	1.
2.	Short Term Capacity Payments	16,044,840	16,044,840	9,941,350	4,198,715	4,537,715	6,811,735	101,007,323	2.
3.	Capacity Payments to Cogenerators (QFs)	29,944,669	29,944,669	29,944,669	29,944,669	29,944,669	29,944,669	359,081,428	3.
4a.	SJRPP Suspension Accrual	422,797	422,797	422,797	422,797	422,797	422,797	5,073,564	4a.
4b.	Return Requirements on SJRPP Suspension Payments	(323,128)	(327,290)	(331,452)	(335,615)	(339,777)	(343,940)	(3,852,557)	4b.
5.	Okeelanta Settlement	3,025,369	3,022,122	3,018,875	3,015,628	3,012,381	3,009,134	36,183,937	6b.
6.	Incremental Plant Security Costs	7,435,438	7,568,849	7,563,849	7,563,849	7,563,849	7,477,516	52,474,009	6c.
7.	Transmission of Electricity by Others	596,818	603,794	596,096	686,645	748,280	693,848	8,419,200	7.
8.	Transmission Revenues from Capacity Sales	(504,100)	(504,100)	(486,800)	(425,850)	(527,000)	(704,000)	(7,295,017)	8.
9.	Total (Lines 1 through 8)	$ 72,108,848	$ 72,241,826	$ 66,135,528	$ 60,536,983	$ 60,829,059	$ 62,777,904	$ 740,657,792	9.
10.	Jurisdictional Separation Factor (a)	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	N/A	10.
11.	Jurisdictional Capacity Charges	71,274,556	71,405,995	65,370,347	59,836,576	60,125,272	62,051,570	732,088,455	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 66,529,090	$ 66,660,529	$ 60,624,881	$ 55,091,110	$ 55,379,806	$ 57,306,104	$ 675,142,863	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 55,373,132	$ 56,445,373	$ 55,999,419	$ 51,500,102	$ 45,765,552	$ 45,016,187	$ 572,906,337	14.
15.	Prior Period True-up Provision	2,393,762	2,393,762	2,393,763	2,393,763	2,393,763	2,393,763	28,725,148	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 57,766,894	$ 58,839,135	$ 58,393,182	$ 53,893,865	$ 48,159,315	$ 47,409,950	$ 601,631,485	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(8,762,196)	(7,821,394)	(2,231,699)	(1,197,245)	(7,220,491)	(9,896,155)	(73,511,378)	17.
18.	Interest Provision for Month	(38,421)	(50,306)	(58,586)	(63,205)	(70,593)	(82,809)	(381,495)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(22,037,196)	(33,231,575)	(43,497,038)	(48,181,086)	(51,835,299)	(61,520,146)	28,725,148	19.
20.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(2,393,762)	(2,393,762)	(2,393,763)	(2,393,763)	(2,393,763)	(2,393,763)	(28,725,148)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (40,281,658)	$ (50,547,121)	$ (55,231,169)	$ (58,885,382)	$ (68,570,229)	$ (80,942,956)	$ (80,942,956)	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, fi
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket N
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATE/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$ 189,565,905	$ 177,228,528	$ 12,337,377	7.0 %
2.	Short Term Capacity Payments	101,007,323	84,454,210	16,553,113	19.6 %
3.	Capacity Payments to Cogenerators (QF's)	359,081,428	350,288,484	8,792,944	2.5 %
4a.	SJRPP Suspension Accrual	5,073,564	5,073,564	0	0.0 %
4b.	Return Requirements on SJRPP Suspension Payments	(3,852,557)	(3,852,557)	(0)	0.0 %
5.	Okeelanta Settlement	36,183,937	36,180,354	3,583	0.0 %
6.	Incremental Plant Security Costs	52,474,009	13,673,611	38,800,398	283.8 %
7.	Transmission of Electricity by Others	8,419,200	6,259,386	2,159,814	34.5 %
8.	Transmission Revenues from Capacity Sales	(7,295,017)	(4,235,810)	(3,059,207)	72.2 %
9.	Total (Lines 1 through 8)	$ 740,657,792	$ 665,069,770	$ 75,588,022	11.4 %
9.	Jurisdictional Separation Factor	98.84301%	98.84301%	0	0.0 %
10.	Jurisdictional Capacity Charges	$ 732,088,455	$ 657,374,979	$ 74,713,476	11.4 %
11.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(56,945,592)	(56,945,592)	0	N/A
12.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 675,142,863	$ 600,429,387	$ 74,713,476	12.4 %
13.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 572,906,337	$ 571,704,239	$ 1,202,097	0.2 %
14.	Prior Period True-up Provision	28,725,148	28,725,148	0	N/A
15.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 601,631,485	$ 600,429,387	$ 1,202,097	0.2 %
16.	True-up Provision for Period - Over/(Under) Recovery (Line 15 - Line 12)	$ (73,511,378)	$0	$ (73,511,378)	N/A
17.	Interest Provision for Period	(381,495)	0	(381,495)	N/A
18.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	28,725,148	28,725,148	0	N/A
19.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	0	(7,050,083)	N/A
20.	Prior Period True-up Provision - Collected/(Refunded) this Period	(28,725,148)	(28,725,148)	0	N/A
21.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	$ (80,942,956)	$0	$ (80,942,956)	N/A

Notes: **(a) Per K. M. Dubin's Testimony Appendix III, Page 3, Docket No. 030001-EI, filed September 12, 2003.**
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 040001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-81
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 9
COMPANY/ FP+L
WITNESS. K.M. Dubin (KMD-5
DATE: 11-08-04

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2005 – December 2005

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		(a) DOLLARS		(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,616,133,562		94,398,459	3.8307
2	Nuclear Fuel Disposal Costs (E2)	21,509,414		23,120,944	0.0930
3	Fuel Related Transactions (E2)	11,344,023		0	0.0000
3b	Incremental Hedging Costs (E2)	553,145		0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(46,912,909)		(1,074,064)	4.3678
5	TOTAL COST OF GENERATED POWER	$3,602,627,235		93,324,395	3.8603
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	230,258,913		11,977,473	1.9224
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	24,343,065		646,000	3.7683
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	26,842,775		573,396	4.6814
9		0		0	0.0000
10		0		0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$9,531,433		0	0.0000
12	Payments to Qualifying Facilities (E8)	160,556,000		7,227,963	2.2213
13	TOTAL COST OF PURCHASED POWER	$451,532,186		20,424,832	2.2107
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			113,749,227	
15	Fuel Cost of Economy Sales (E6)	(115,254,050)		(2,460,000)	4.6851
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,408,227)		(448,894)	0.3137
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(11,084,350)		(2,908,894)	0.3811
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($127,746,627)		(2,908,894)	4.3916
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$3,926,412,793		110,840,333	3.5424
21	Net Unbilled Sales	(8,002,929)	**	(225,918)	(0.0077)
22	Company Use	11,779,238	**	332,521	0.0114
23	T & D Losses	255,216,832	**	7,204,622	0.2465
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$3,926,412,793		103,529,108	3.7926
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$19,687,819		519,114	3.7926
26	Jurisdictional MWH Sales	$3,906,724,974		103,009,994	3.7926
27	Jurisdictional Loss Multiplier	-		-	1.00065
28	Jurisdictional MWH Sales Adjusted for Line Losses	$3,909,264,345		103,009,994	3.7950
29	FINAL TRUE-UP JAN 03 - DEC 03 $41,808.676 (overrecovery) / EST/ACT TRUE-UP JAN 04 - DEC 04 $182,196,299 underrecovery	140,387,623		103,009,994	0.1363
30	TOTAL JURISDICTIONAL FUEL COST	$4,049,651,968		103,009,994	3.9313
31	Revenue Tax Factor				1.01597
32	Fuel Factor Adjusted for Taxes				3.9941
33	GPIF ***	$6,615,282		103,009,994	0.0064
34	Fuel Factor including GPIF (Line 32 + Line 33)				4.0005
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				4.001

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1. Estimated/Actual over/(under) recovery (January 2004 - December 2004)	$ (182,196,299)
2.Final over/(under) recovery (January 2003 - December 2003)	$ 41,808,676
3.Total over/(under) recovery to be included in the January 2005 - December 2005 projected period (Schedule E1, Line 29)	$ (140,387,623)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	103,009,994
5. True-Up Factor (Lines 3/4) c/kWh:	(0.1363)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1. TOTAL AMOUNT OF ADJUSTMENTS:	147,052,976
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$6,615,282
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 140,437,694
2. TOTAL JURISDICTIONAL SALES (MWH)	103,009,994
3. ADJUSTMENT FACTORS c/kWh:	0.1428
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0064
B. TRUE-UP FACTOR	0.1363

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2005 - DECEMBER 2005

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.67	32.62
OFF PEAK	69.33	67.38
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$3,926,412,793	$1,280,795,853	$2,645,616,940
2	MWH SALES	103,529,108	31,752,377	71,776,731
3	COST PER KWH SOLD	3.7926	4.0337	3.6859
4	JURISDICTIONAL LOSS FACTOR	1.00065	1.00065	1.00065
5	JURISDICTIONAL FUEL FACTOR	3.7950	4.0363	3.6883
6	TRUE-UP	0.1363	0.1363	0.1363
7				
8	TOTAL	3.9313	4.1726	3.8246
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	3.9941	4.2392	3.8857
11	GPIF	0.0064	0.0064	0.0064
12	RECOVERY FACTOR including GPIF	4.0005	4.2456	3.8921
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.001	4.246	3.892

HOURS:	ON-PEAK	24.62	%
	OFF-PEAK	75.38	%

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2005 - DECEMBER 2005

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		4.001	1.00201	4.009
A-1*	SL-1, OL-1, PL-1		3.949	1.00201	3.957
B	GSD-1		4.001	1.00194	4.008
C	GSLD-1 & CS-1		4.001	1.00097	4.004
D	GSLD-2, CS-2, OS-2 & MET		4.001	0.99390	3.976
E	GSLD-3 & CS-3		4.001	0.95678	3.828
A	RST-1, GST-1	ON-PEAK	4.246	1.00201	4.254
		OFF-PEAK	3.892	1.00201	3.900
B	GSDT-1	ON-PEAK	4.246	1.00194	4.254
	CILC-1(G)	OFF-PEAK	3.892	1.00194	3.900
C	GSLDT-1 &	ON-PEAK	4.246	1.00097	4.250
	CST-1	OFF-PEAK	3.892	1.00097	3.896
D	GSLDT-2 &	ON-PEAK	4.246	0.99513	4.225
	CST-2	OFF-PEAK	3.892	0.99513	3.873
E	GSLDT-3,CST-3,	ON-PEAK	4.246	0.95678	4.062
	CILC -1(T) & ISST-1(T)	OFF-PEAK	3.892	0.95678	3.724
F	CILC -1(D) &	ON-PEAK	4.246	0.99349	4.218
	ISST-1(D)	OFF-PEAK	3.892	0.99349	3.867

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

Florida Power & Light Company
2003 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	53,362,062	1.07281827	57,247,795	0.932124	3,885,733	1.00201
2							
3	GS-1 Sec	5,858,928	1.07281827	6,285,565	0.932124	426,637	1.00201
4							
5	GSD-1 Pri	65,919	1.04657532	68,989	0.955497	3,070	
6	GSD-1 Sec	22,196,556	1.07281827	23,812,870	0.932124	1,616,315	
7	Subtotal GSD-1	22,262,475	1.07274057	23,881,860	0.932192	1,619,385	1.00194
8							
9	OS-2 Pri	20,360	1.04657532	21,309	0.955497	948	
10	OS-2 Sec	-	1.07281827	-	0.000000	-	
11	Subtotal OS-2	20,360	1.04657532	21,309	0.955497	948	0.97750
12							
13	GSLD-1 Pri	381,079	1.04657532	398,828	0.955497	17,749	
14	GSLD-1 Sec	9,629,926	1.07281827	10,331,161	0.932124	701,235	
15	Subtotal GSLD-1	10,011,005	1.07181931	10,729,989	0.932993	718,983	1.00108
16							
17	CS-1 Pri	55,410	1.04657532	57,990	0.955497	2,581	
18	CS-1 Sec	183,213	1.07281827	196,555	0.932124	13,341	
19	Subtotal CS-1	238,623	1.06672450	254,545	0.937449	15,922	0.99632
20							
21	Subtotal GSLD-1 / CS-1	10,249,628	1.07170069	10,984,534	0.933096	734,905	1.00097
22							
23	GSLD-2 Pri	395,254	1.04657532	413,663	0.955497	18,409	
24	GSLD-2 Sec	1,014,726	1.07281827	1,088,616	0.932124	73,891	
25	Subt GSLD-2	1,409,980	1.06546169	1,502,279	0.938560	92,300	0.99514
26							
27	CS-2 Pri	27,756	1.04657532	29,049	0.955497	1,293	
28	CS-2 Sec	68,799	1.07281827	73,809	0.932124	5,010	
29	Subtotal CS-2	96,556	1.06527437	102,858	0.938725	6,303	0.99497
30							
31	Subtotal GSLD-2 / CS-2	1,506,535	1.06544968	1,605,138	0.938571	98,602	0.99513
32							
33	GSLD-3 Trn	180,521	1.02438901	184,923	0.976192	4,403	0.95678
34							
35	CS-3 Trn	0	1.02438901	0	0.000000	0	0.00000
36							
37	Subtotal GSLD-3 / CS-3	180,521	1.02438901	184,923	0.976192	4,403	0.95678
38							
39	ISST-1 Sec	0	1.07281827	0	0.000000	0	0.00000
40							
41	SST-1 Pri	4,494	1.04657532	4,704	0.955497	209	
42	SST-1 Sec	18,259	1.07281827	19,589	0.932124	1,330	
43	Subtotal SST-1 (D)	22,754	1.06763473	24,293	0.936650	1,539	0.99717
44							
45	SST-1 Trn	144,682	1.02438901	148,211	0.976192	3,529	0.95678
46							
47	CILC-1D Pri	1,082,146	1.04657532	1,132,548	0.955497	50,401	
48	CILC-1D Sec	2,028,149	1.07281827	2,175,835	0.932124	147,686	
49	Subtotal CILC-1D	3,110,295	1.06368772	3,308,383	0.940126	198,088	0.99349
50							
51	CILC-1G Pri	700	1.04657532	733	0.955497	33	
52	CILC-1G Sec	235,235	1.07281827	252,365	0.932124	17,129	
53	Subtotal CILC-1G	235,936	1.07274038	253,098	0.932192	17,162	1.00194
54							
55	Subtotal CILC-1D / CILC-1G	3,346,231	1.06432600	3,561,481	0.939562	215,250	0.99408
56							
57	Subtotal GSD-1 & CILC-1G	22,498,411	1.07274056	24,134,958	0.932192	1,636,547	1.00194
58							
59	CILC-1T Trn	1,468,366	1.02438901	1,504,178	0.976192	35,812	0.95678
60							

Florida Power & Light Company
2003 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
61	Subtotal ISST-D & CILC-1D	3,110,295	1.06368772	3,308,383	0.940126	198,088	0.99349
62							
63	MET Pri	93,198	1.04657532	97,539	0.955497	4,341	0.97750
64							
65	Subtotal OS-2, GSLD-2, CS-2, & MET	1,620,094	1.06412671	1,723,985	0.939738	103,891	0.99390
66							
67	OL-1 Sec	109,597	1.07281827	117,578	0.932124	7,981	1.00201
68							
69	SL-1 Sec	426,217	1.07281827	457,254	0.932124	31,036	1.00201
70							
71	Subtotal OL-1 / SL-1	535,815	1.07281827	574,832	0.932124	39,017	1.00201
72							
73	SL-2 Sec	67,673	1.07281827	72,601	0.932124	4,928	1.00201
74							
75	RTP-1 Pri	0	1.04657532	0	0.000000	0	
76	RTP-1 Sec	38,247	1.07281827	41,032	0.932124	2,785	
77	Subtotal RTP-1	38,247	1.07281827	41,032	0.932124	2,785	1.00201
78							
79	RTP-2 Pri	69,791	1.04657532	73,042	0.955497	3,251	
80	RTP-2 Sec	111,877	1.07281827	120,024	0.932124	8,147	
81	Subtotal RTP-2	181,669	1.06273654	193,066	0.940967	11,397	0.99260
82							
83	RTP-3 Trn	0	1.02438901	0	0.000000	0	0.00000
84							
85	Total FPSC	99,339,144	1.07136372	106,428,356	0.933390	7,089,211	1.00065
86							
87	Total FERC Sales	1,511,574	1.02438901	1,548,440	0.976192	36,866	
88							
89	Total Company	100,850,719	1.07065966	107,976,796	0.934004	7,126,077	
90							
91	Company Use	139,794	1.07281827	149,974	0.932124	10,180	
92							
93	Total FPL	100,990,513	1.07066264	108,126,769	0.934001	7,136,257	1.00000
94							
95	**Summary of Sales by Voltage:**						
96							
97	Transmission	3,305,143	1.02438901	3,385,752	0.976192	80,609	
98							
99	Primary	2,196,109	1.04657532	2,298,394	0.955497	102,284	
100							
101	Secondary	95,349,467	1.07281827	102,292,650	0.932124	6,943,183	
102							
103	Total	100,850,719	1.07065966	107,976,796	0.934004	7,126,077	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2005 - DECEMBER 2005

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$249,062,689	$229,494,456	$248,849,987	$264,235,844	$322,553,153	$340,576,822	$1,654,772,951	A1
1a	NUCLEAR FUEL DISPOSAL	2,033,221	1,836,458	2,033,221	1,587,482	1,515,688	1,738,342	10,744,412	1a
1b	COAL CAR INVESTMENT	357,992	355,784	353,577	351,369	349,162	346,954	2,114,838	1b
1d	GAS LATERAL ENHANCEMENTS	47,580	47,140	46,700	46,260	45,819	45,379	278,878	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1g	INCREMENTAL HEDGING COSTS	59,542	35,542	47,707	35,542	49,580	35,542	263,455	1g
2	FUEL COST OF POWER SOLD	(12,813,229)	(11,745,573)	(10,540,691)	(8,393,387)	(7,532,681)	(10,253,775)	(61,279,336)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(750,000)	(885,800)	(787,500)	(736,750)	(672,000)	(1,190,100)	(5,022,150)	2a
3	FUEL COST OF PURCHASED POWER	22,005,184	18,732,575	17,921,994	14,381,067	20,527,668	16,225,115	109,793,603	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	799,033	798,170	797,307	796,444	795,581	794,718	4,781,253	3b
3c	QUALIFYING FACILITIES	13,899,000	12,887,000	13,908,000	13,598,000	13,924,000	13,630,000	81,846,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	5,194,735	4,768,471	5,385,712	5,926,802	6,084,294	2,705,396	30,065,410	4
4a	FUEL COST OF SALES TO FKEC / CKW	(3,354,286)	(3,373,026)	(3,414,130)	(3,662,360)	(3,859,379)	(4,014,266)	(21,677,447)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$276,541,461	$252,951,197	$274,601,884	$288,166,313	$353,780,885	$360,640,127	$1,806,681,867	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	7,871,434	7,643,474	7,321,581	7,506,178	7,862,448	9,376,285	47,581,400	6
7	COST PER KWH SOLD (¢/KWH)	3.5132	3.3094	3.7506	3.8391	4.4996	3.8463	3.7970	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	3.5155	3.3115	3.7530	3.8416	4.5026	3.8488	3.7995	7b
9	TRUE-UP (¢/KWH)	0.0782	0.0806	0.0841	0.0820	0.0783	0.0657	0.0776	9
10	TOTAL	3.5937	3.3921	3.8371	3.9236	4.5809	3.9145	3.8771	10
11	REVENUE TAX FACTOR 0.01597	0.0574	0.0542	0.0613	0.0627	0.0732	0.0625	0.0619	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	3.6511	3.4463	3.8984	3.9863	4.6541	3.9770	3.9390	12
13	GPIF (¢/KWH)	0.0070	0.0072	0.0076	0.0074	0.0070	0.0059	0.0070	13
14	RECOVERY FACTOR including GPIF	3.6581	3.4535	3.9060	3.9937	4.6611	3.9829	3.9460	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.658	3.454	3.906	3.994	4.661	3.983	3.946	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2005 - DECEMBER 2005

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$381,888,807	$373,972,172	$343,270,872	$326,700,974	$270,114,226	$265,413,560	$3,616,133,562	A1
1a	NUCLEAR FUEL DISPOSAL	1,983,357	1,983,357	1,919,376	1,453,692	1,410,567	2,014,653	$21,509,414	1a
1b	COAL CAR INVESTMENT	344,747	342,539	340,332	338,124	335,917	333,709	$4,150,206	1b
1d	GAS LATERAL ENHANCEMENTS	44,939	0	0	0	0	0	$323,817	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	6,870,000	0	$6,870,000 $0	1e
1g	INCREMENTAL HEDGING COSTS	66,742	66,742	35,542	35,542	49,580	35,542	$553,145	1g
2	FUEL COST OF POWER SOLD	(9,436,953)	(9,570,193)	(9,216,004)	(7,905,823)	(8,824,500)	(10,429,469)	($116,662,278)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(1,395,800)	(1,422,300)	(576,300)	(427,100)	(842,000)	(1,398,700)	($11,084,350)	2a
3	FUEL COST OF PURCHASED POWER	25,581,676	23,624,151	17,930,638	17,451,974	16,675,160	19,201,711	$230,258,913	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	793,855	792,991	792,128	791,265	790,402	789,539	$9,531,433	3b
3c	QUALIFYING FACILITIES	13,796,000	13,849,000	13,609,000	13,936,000	11,677,000	11,843,000	$160,556,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	2,871,499	2,931,412	2,834,577	4,142,850	4,089,990	4,250,102	$51,185,840	4
4a	FUEL COST OF SALES TO FKEC / CKW	(4,275,422)	(4,431,069)	(4,499,500)	(4,295,460)	(4,035,242)	(3,698,767)	($46,912,909)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$412,263,447	$402,138,802	$366,440,661	$352,222,038	$298,311,100	$288,354,880	$3,926,412,793	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,794,123	10,257,836	10,200,267	9,238,929	8,188,913	8,267,640	103,529,108	6
7	COST PER KWH SOLD (¢/KWH)	4.2093	3.9203	3.5925	3.8124	3.6429	3.4878	3.7926	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	4.2120	3.9229	3.5948	3.8148	3.6452	3.4900	3.7950	7b
9	TRUE-UP (¢/KWH)	0.0629	0.0600	0.0604	0.0667	0.0752	0.0745	0.0714	9
10	TOTAL	4.2749	3.9829	3.6552	3.8815	3.7204	3.5645	3.8664	10
11	REVENUE TAX FACTOR 0.01597	0.0683	0.0636	0.0584	0.0620	0.0594	0.0569	0.0617	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	4.3432	4.0465	3.7136	3.9435	3.7798	3.6214	3.9281	12
13	GPIF (¢/KWH)	0.0057	0.0054	0.0054	0.0060	0.0068	0.0067	0.0064	13
14	RECOVERY FACTOR including GPIF	4.3489	4.0519	3.7190	3.9495	3.7866	3.6281	3.9345	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.349	4.052	3.719	3.950	3.787	3.628	3.935	15

Florida Power & Light Company
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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$33,087,835	$37,458,500	$51,577,745	$69,599,003	$106,072,579	$83,666,800
2	Light Oil	$2,216,880	$803,350	$231,920	$48,330	$2,030,150	$188,920
3	Coal	$8,507,240	$7,707,010	$7,412,740	$6,974,450	$8,398,090	$8,185,290
4	Gas	$198,076,044	$177,057,456	$182,480,002	$181,854,572	$200,527,134	$242,086,322
5	Nuclear	$7,174,690	$6,468,140	$7,147,580	$5,759,490	$5,525,200	$6,449,490
6	***Total***	$249,062,689	$229,494,456	$248,849,987	$264,235,844	$322,553,153	$340,576,822
	System Net Generation (MWH)						
7	Heavy Oil	647,984	773,297	1,047,366	1,406,814	2,166,583	1,704,318
8	Light Oil	14,534	5,108	1,963	443	16,626	1,746
9	Coal	549,042	497,851	477,618	459,315	554,244	540,233
10	Gas	3,333,275	2,995,902	3,200,666	3,384,807	3,793,417	4,691,752
11	Nuclear	2,185,554	1,974,049	2,185,554	1,706,419	1,629,247	1,868,582
12	***Total***	6,730,389	6,246,207	6,913,167	6,957,798	8,160,117	8,806,631
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	1,006,964	1,144,805	1,595,356	2,183,270	3,333,852	2,619,546
14	Light Oil (BBLS)	39,562	14,249	4,215	885	36,680	3,500
15	Coal (TONS)	279,471	253,982	253,056	237,815	276,278	269,216
16	Gas (MCF)	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
17	Nuclear (MBTU)	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,048
	BTU Burned (MMBTU)						
18	Heavy Oil	6,444,569	7,326,754	10,210,278	13,972,926	21,336,650	16,765,090
19	Light Oil	230,646	83,072	24,572	5,158	213,844	20,406
20	Coal	5,351,378	4,852,657	4,663,963	4,386,011	5,285,164	5,151,205
21	Gas	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
22	Nuclear	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,048
23	***Total***	61,481,089	56,721,391	62,806,877	62,904,503	74,041,570	77,647,208

Florida Power & Light Company
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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
	Generation Mix (%MWH)						
24	Heavy Oil	9.63%	12.38%	15.15%	20.22%	26.55%	19.35%
25	Light Oil	0.22%	0.08%	0.03%	0.01%	0.20%	0.02%
26	Coal	8.16%	7.97%	6.91%	6.60%	6.79%	6.13%
27	Gas	49.53%	47.96%	46.30%	48.65%	46.49%	53.28%
28	Nuclear	32.47%	31.60%	31.61%	24.53%	19.97%	21.22%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	32.8590	32.7204	32.3299	31.8783	31.8168	31.9394
31	Light Oil ($/BBL)	56.0356	56.3794	55.0225	54.6102	55.3476	53.9771
32	Coal ($/ton)	30.4405	30.3447	29.2929	29.3272	30.3972	30.4042
33	Gas ($/MCF)	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
34	Nuclear ($/MBTU)	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	5.1342	5.1126	5.0516	4.9810	4.9714	4.9905
36	Light Oil	9.6116	9.6705	9.4384	9.3699	9.4936	9.2581
37	Coal	1.5897	1.5882	1.5894	1.5902	1.5890	1.5890
38	Gas	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
39	Nuclear	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	9,946	9,475	9,749	9,932	9,848	9,837
41	Light Oil	15,869	16,263	12,518	11,643	12,862	11,687
42	Coal	9,747	9,747	9,765	9,549	9,536	9,535
43	Gas	7,606	7,573	7,438	7,517	7,648	7,407
44	Nuclear	11,028	11,028	11,028	11,191	11,167	11,217
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	5.1063	4.8440	4.9245	4.9473	4.8958	4.9091
46	Light Oil	15.2531	15.7273	11.8146	10.9097	12.2107	10.8202
47	Coal	1.5495	1.5481	1.5520	1.5184	1.5152	1.5151
48	Gas	5.9424	5.9100	5.7013	5.3727	5.2862	5.1598
49	Nuclear	0.3283	0.3277	0.3270	0.3375	0.3391	0.3452
50	***Total***	3.7006	3.6741	3.5997	3.7977	3.9528	3.8673

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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$81,002,720	$84,894,368	$83,052,400	$73,649,915	$37,664,690	$26,834,391	$768,560,945
2	Light Oil	$6,036,540	$4,394,280	$1,663,880	$689,530	$111,750	$68,010	$18,483,540
3	Coal	$8,340,990	$8,343,510	$8,170,830	$8,354,940	$8,327,810	$8,677,420	$97,400,320
4	Gas	$279,078,237	$268,919,464	$243,216,162	$238,368,779	$218,637,616	$222,198,659	$2,652,500,447
5	Nuclear	$7,430,320	$7,420,550	$7,167,600	$5,637,810	$5,372,360	$7,635,080	$79,188,310
6	***Total***	$381,888,807	$373,972,172	$343,270,872	$326,700,974	$270,114,226	$265,413,560	$3,616,133,562
	System Net Generation (MWH)							
7	Heavy Oil	1,628,985	1,707,451	1,686,888	1,517,309	771,735	554,092	15,612,822
8	Light Oil	43,226	32,195	12,607	6,547	1,001	458	136,454
9	Coal	549,508	549,645	538,561	550,462	536,695	559,183	6,362,357
10	Gas	5,210,262	5,068,958	4,628,617	4,576,916	4,202,601	4,078,709	49,165,882
11	Nuclear	2,131,954	2,131,954	2,063,180	1,562,606	1,516,250	2,165,595	23,120,944
12	***Total***	9,563,935	9,490,203	8,929,853	8,213,840	7,028,282	7,358,037	94,398,459
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	2,529,125	2,646,073	2,600,413	2,335,576	1,201,148	861,133	24,057,261
14	Light Oil (BBLS)	110,188	81,092	30,889	13,143	2,107	1,255	337,765
15	Coal (TONS)	274,194	274,328	268,556	274,479	273,224	284,678	3,219,277
16	Gas (MCF)	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
17	Nuclear (MBTU)	23,967,112	23,967,112	23,193,978	17,690,118	16,831,692	23,886,181	257,760,861
	BTU Burned (MMBTU)							
18	Heavy Oil	16,186,398	16,934,872	16,642,645	14,947,685	7,687,350	5,511,248	153,966,465
19	Light Oil	642,397	472,764	180,081	76,621	12,281	7,315	1,969,157
20	Coal	5,245,828	5,246,001	5,136,962	5,249,295	5,230,722	5,449,722	61,248,908
21	Gas	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
22	Nuclear	23,967,112	23,967,112	23,193,978	17,690,118	16,831,692	23,886,181	257,760,861
23	***Total***	86,480,486	85,343,803	79,999,107	71,795,894	60,204,264	65,075,240	844,501,431

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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
	Generation Mix (%MWH)							
24	Heavy Oil	17.03%	17.99%	18.89%	18.47%	10.98%	7.53%	16.54%
25	Light Oil	0.45%	0.34%	0.14%	0.08%	0.01%	0.01%	0.14%
26	Coal	5.75%	5.79%	6.03%	6.70%	7.64%	7.60%	6.74%
27	Gas	54.48%	53.41%	51.83%	55.72%	59.80%	55.43%	52.08%
28	Nuclear	22.29%	22.46%	23.10%	19.02%	21.57%	29.43%	24.49%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	32.0280	32.0832	31.9382	31.5339	31.3572	31.1617	31.9472
31	Light Oil ($/BBL)	54.7840	54.1888	53.8664	52.4637	53.0375	54.1912	54.7231
32	Coal ($/ton)	30.4200	30.4144	30.4251	30.4393	30.4798	30.4815	30.2553
33	Gas ($/MCF)	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
34	Nuclear ($/MBTU)	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	5.0044	5.0130	4.9903	4.9272	4.8996	4.8690	4.9917
36	Light Oil	9.3969	9.2949	9.2396	8.9992	9.0994	9.2973	9.3865
37	Coal	1.5900	1.5905	1.5906	1.5916	1.5921	1.5923	1.5902
38	Gas	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
39	Nuclear	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	9,936	9,918	9,866	9,851	9,961	9,946	9,862
41	Light Oil	14,861	14,684	14,284	11,703	12,269	15,972	14,431
42	Coal	9,546	9,544	9,538	9,536	9,746	9,746	9,627
43	Gas	7,761	7,639	7,528	7,392	7,244	7,409	7,517
44	Nuclear	11,242	11,242	11,242	11,321	11,101	11,030	11,148
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	4.9726	4.9720	4.9234	4.8540	4.8805	4.8429	4.9226
46	Light Oil	13.9651	13.6490	13.1981	10.5320	11.1638	14.8493	13.5456
47	Coal	1.5179	1.5180	1.5172	1.5178	1.5517	1.5518	1.5309
48	Gas	5.3563	5.3052	5.2546	5.2081	5.2024	5.4478	5.3950
49	Nuclear	0.3485	0.3481	0.3474	0.3608	0.3543	0.3526	0.3425
50	***Total***	3.9930	3.9406	3.8441	3.9774	3.8432	3.6071	3.8307

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	52,423	24.1	95.0	75.0	9,390	Heavy Oil BBLS ->	71,978	6,400,003	460,656	2,368,691	4.5185
2			18,746					Gas MCF ->	207,611	1,000,000	207,611	1,619,028	8.6368
3													
4	TRKY O 2	397	19,653	10.3	93.7	51.4	10,526	Heavy Oil BBLS ->	28,324	6,400,001	181,273	932,151	4.7430
5			10,770					Gas MCF ->	138,969	1,000,000	138,969	1,083,679	10.0624
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,919,300	0.3690
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,586,400	0.3050
10													
11	FT LAUD4	443	290,193	88.0	94.7	93.0	7,715	Gas MCF ->	2,238,768	1,000,000	2,238,768	17,458,380	6.0161
12													
13	FT LAUD5	442	275,635	83.8	93.6	88.5	7,906	Gas MCF ->	2,179,029	1,000,000	2,179,029	16,992,476	6.1649
14													
15	PT EVER1	211	5,990	6.4	95.0	45.0	11,424	Heavy Oil BBLS ->	7,823	6,400,020	50,068	258,012	4.3077
16			4,110					Gas MCF ->	65,306	1,000,000	65,306	509,309	12.3925
17													
18	PT EVER2	211	6,608	6.9	94.4	46.3	10,979	Heavy Oil BBLS ->	8,288	6,399,969	53,042	273,318	4.1362
19			4,182					Gas MCF ->	65,424	1,000,000	65,424	510,191	12.1997
20													
21	PT EVER3	383	14,860	8.0	95.1	42.3	12,377	Heavy Oil BBLS ->	25,001	6,400,010	160,004	824,426	5.5481
22			7,991					Gas MCF ->	122,820	1,000,000	122,820	957,752	11.9854
23													
24	PT EVER4	390	9,900	5.9	95.6	34.9	13,779	Heavy Oil BBLS ->	18,129	6,400,014	116,023	597,821	6.0388
25			7,308					Gas MCF ->	121,075	1,000,000	121,075	944,128	12.9191
26													
27	RIV 3	275	6,415	5.4	93.8	40.7	12,625	Heavy Oil BBLS ->	9,064	6,400,018	58,010	298,460	4.6525
28			4,693					Gas MCF ->	82,234	1,000,000	82,234	641,183	13.6619
29													
30	RIV 4	281	121,327	69.1	92.8	79.7	9,100	Heavy Oil BBLS ->	170,311	6,399,999	1,089,988	5,607,933	4.6222
31			23,161					Gas MCF ->	224,919	1,000,000	224,919	1,753,969	7.5730
32													

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	618,763	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,709,888	1,000,000	6,709,888	1,909,700	0.3086
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,759,400	0.3341
37	CAP CN 1	398	24,898	14.7	94.2	62.7	10,536	Heavy Oil BBLS ->	37,237	6,400,002	238,316	1,221,742	4.9070
38			18,635					Gas MCF ->	220,364	1,000,000	220,364	1,718,374	9.2212
40	CAP CN 2	398	35,439	18.6	94.7	68.4	10,251	Heavy Oil BBLS ->	52,587	6,400,003	336,559	1,725,427	4.8687
41			19,490					Gas MCF ->	226,527	1,000,000	226,527	1,766,497	9.0638
43	SANFRD 3	140	2,961	5.6	95.8	41.8	11,755	Heavy Oil BBLS ->	4,129	6,399,985	26,428	116,162	3.9232
44			2,824					Gas MCF ->	41,572	1,000,000	41,572	324,161	11.4804
46	PUTNAM 1	250	16,041	8.6	95.3	56.3	9,645	Gas MCF ->	154,710	1,000,000	154,710	1,206,921	7.5239
48	PUTNAM 2	250	14,316	7.7	95.4	53.2	10,044	Gas MCF ->	143,787	1,000,000	143,787	1,121,559	7.8346
50	MANATE 1	821	150,168	28.2	94.4	54.2	10,279	Heavy Oil BBLS ->	238,560	6,399,999	1,526,785	7,834,481	5.2171
51			22,065					Gas MCF ->	243,636	1,000,000	243,636	1,969,498	8.9259
53	MANATE 2	821	80,168	18.0	95.8	42.2	11,122	Heavy Oil BBLS ->	136,372	6,400,000	872,778	4,478,522	5.5864
54			29,726					Gas MCF ->	349,505	1,000,000	349,505	2,825,960	9.5066
56	CUTLER 5	70	2,684	5.2	97.6	41.3	10,935	Gas MCF ->	29,351	1,000,000	29,351	228,888	8.5272
58	CUTLER 6	142	3,893	3.7	96.6	29.2	11,682	Gas MCF ->	45,477	1,000,000	45,477	354,700	9.1112
60	MARTIN 1	813	38,742	12.8	86.6	41.7	12,168	Heavy Oil BBLS ->	71,207	6,400,003	455,724	2,342,148	6.0456
61			38,451					Gas MCF ->	483,554	1,000,000	483,554	3,770,888	9.8070

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	804	78,433	22.7	96.3	54.7	10,711	Heavy Oil BBLS ->	127,955	6,400,002	818,912	4,208,730	5.3660
64			57,353					Gas MCF ->	635,439	1,000,000	635,439	4,955,328	8.6400
66	MARTIN 3	465	257,513	74.4	95.1	86.4	7,158	Gas MCF ->	1,843,253	1,000,000	1,843,253	14,374,046	5.5819
68	MARTIN 4	466	274,667	79.2	94.6	89.6	6,884	Gas MCF ->	1,890,900	1,000,000	1,890,900	14,745,568	5.3685
70	MARTIN 8	1,099		0.0	0.0		0						
72	FM GT	624	14,310	3.1	98.4	48.2	15,850	Light Oil BBLS ->	38,904	5,829,992	226,807	2,189,600	15.3014
74	FL GT	768	71	1.9	91.7	30.8	18,675	Light Oil BBLS ->	216	5,829,314	1,257	8,600	12.1813
75			10,542					Gas MCF ->	196,938	1,000,000	196,938	1,535,942	14.5695
77	PE GT	384	154	3.5	88.3	57.3	17,624	Light Oil BBLS ->	443	5,830,662	2,582	18,700	12.1666
78			9,709					Gas MCF ->	171,237	1,000,000	171,237	1,341,514	13.8174
80	SJRPP 1O	130	84,290	87.1	93.1	99.7	9,640	Coal TONS ->	33,219	24,460,311	812,537	1,306,400	1.5499
82	SJRPP 2O	130	84,864	87.7	93.6	99.7	9,500	Coal TONS ->	32,961	24,460,316	806,232	1,296,200	1.5274
84	SCHER #4	648	379,888	78.8	94.2	89.7	9,826	Coal TONS ->	213,292	17,500,004	3,732,609	5,904,600	1.5543
86	FMREP 1	1,451	822,450	76.2	87.1	86.3	6,897	Gas MCF ->	5,672,200	1,000,000	5,672,200	44,278,455	5.3837
88	SNREP4	938	549,897	78.8	95.7	90.7	6,885	Gas MCF ->	3,785,782	1,000,000	3,785,782	29,573,130	5.3779
90	SNREP5	938	507,031	72.7	95.2	87.3	6,809	Gas MCF ->	3,452,432	1,000,000	3,452,432	26,999,502	5.3250
92	MANATE 3	1,105		0.0	0.0		0						

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	166	29,201	11.8	97.1	81.2	10,926	Gas MCF ->	319,055	1,000,000	319,055	2,515,300	8.6139
96	MR SC	163		0.0	0.0		0						
98	TOTAL	13,446	3,556,626	0.0			8,062				28,673,479	181,385,180	5.0999

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	103,636	45.2	95.0	87.3	8,983	Heavy Oil BBLS ->	140,224	6,400,001	897,432	4,586,958	4.4260
2			16,835					Gas MCF ->	184,754	1,000,000	184,754	1,439,169	8.5485
3													
4	TRKY O 2	397	62,538	28.3	83.7	74.1	9,414	Heavy Oil BBLS ->	86,641	6,400,000	554,502	2,834,135	4.5318
5			13,088					Gas MCF ->	157,481	1,000,000	157,481	1,226,709	9.3727
6													
7	TRKY N 3	717	469,777	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,276,049	1,000,000	5,276,049	1,730,300	0.3683
8													
9	TRKY N 4	717	469,777	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,276,049	1,000,000	5,276,049	1,430,100	0.3044
10													
11	FT LAUD4	443	260,154	87.4	94.7	92.3	7,707	Gas MCF ->	2,004,950	1,000,000	2,004,950	15,617,647	6.0032
12													
13	FT LAUD5	442	246,850	83.1	93.6	87.7	7,890	Gas MCF ->	1,947,564	1,000,000	1,947,564	15,170,627	6.1457
14													
15	PT EVER1	211	7,651	10.6	95.0	50.3	11,435	Heavy Oil BBLS ->	9,889	6,399,972	63,287	324,997	4.2479
16			7,320					Gas MCF ->	107,899	1,000,000	107,899	840,458	11.4818
17													
18	PT EVER2	211	10,972	12.5	84.3	57.3	10,244	Heavy Oil BBLS ->	13,486	6,400,007	86,307	443,196	4.0394
19			6,816					Gas MCF ->	95,903	1,000,000	95,903	746,991	10.9595
20													
21	PT EVER3	383	7,610	4.6	23.8	54.2	11,280	Heavy Oil BBLS ->	12,291	6,400,023	78,661	403,929	5.3079
22			4,307					Gas MCF ->	55,766	1,000,000	55,766	434,422	10.0864
23													
24	PT EVER4	390	39,740	20.2	95.6	58.9	11,572	Heavy Oil BBLS ->	66,090	6,399,998	422,973	2,172,028	5.4656
25			13,162					Gas MCF ->	189,225	1,000,000	189,225	1,473,974	11.1991
26													
27	RIV 3	275	125,164	74.7	93.8	84.1	8,444	Heavy Oil BBLS ->	163,640	6,399,999	1,047,294	5,355,646	4.2789
28			12,934					Gas MCF ->	118,828	1,000,000	118,828	925,537	7.1561
29													
30	RIV 4	281	4,972	6.8	92.8	37.6	14,590	Heavy Oil BBLS ->	7,541	6,399,981	48,263	246,759	4.9633
31			7,953					Gas MCF ->	140,309	1,000,000	140,309	1,092,916	13.7427
32													

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	558,883	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,060,552	1,000,000	6,060,552	1,721,600	0.3080
34													
35	ST LUC 2	726	475,613	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,157,500	1,000,000	5,157,500	1,586,100	0.3335
36													
37	CAP CN 1	398	12,725	6.5	13.5	76.2	9,785	Heavy Oil BBLS ->	18,693	6,399,999	119,634	610,715	4.7992
38			4,757					Gas MCF ->	51,424	1,000,000	51,424	400,512	8.4201
39													
40	CAP CN 2	398	89,092	39.4	94.7	83.2	9,655	Heavy Oil BBLS ->	129,499	6,399,999	828,792	4,230,955	4.7490
41			16,354					Gas MCF ->	189,246	1,000,000	189,246	1,474,089	9.0135
42													
43	SANFRD 3	140	3,874	9.1	95.8	46.6	11,901	Heavy Oil BBLS ->	5,356	6,399,940	34,277	151,203	3.9035
44			4,653					Gas MCF ->	67,203	1,000,000	67,203	523,476	11.2493
45													
46	PUTNAM 1	250	30	18.8	95.3	69.3	8,937	Light Oil BBLS ->	44	5,828,767	255	2,000	6.6667
47			31,620					Gas MCF ->	282,601	1,000,000	282,601	2,202,397	6.9653
48													
49	PUTNAM 2	250	7	14.7	95.4	64.4	9,318	Light Oil BBLS ->	11	5,831,858	66	500	6.7568
50			24,708					Gas MCF ->	230,220	1,000,000	230,220	1,794,077	7.2613
51													
52	MANATE 1	821	102,033	20.9	94.4	61.0	10,246	Heavy Oil BBLS ->	160,858	6,399,998	1,029,488	5,266,257	5.1613
53			13,194					Gas MCF ->	151,090	1,000,000	151,090	1,218,384	9.2346
54													
55	MANATE 2	821	67,538	15.1	95.8	52.4	10,897	Heavy Oil BBLS ->	112,492	6,400,000	719,951	3,682,852	5.4530
56			15,927					Gas MCF ->	189,580	1,000,000	189,580	1,529,636	9.6042
57													
58	CUTLER 5	70	2,384	5.1	97.6	36.5	13,746	Gas MCF ->	32,771	1,000,000	32,771	255,224	10.7057
59													
60	CUTLER 6	142	4,510	4.7	96.6	33.4	12,067	Gas MCF ->	54,427	1,000,000	54,427	423,932	9.3992
61													
62	MARTIN 1	813		0.0	0.0		0						
63													

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MARTIN 2	804	135,753	39.8	96.3	65.1	10,497	Heavy Oil BBLS ->	218,108	6,400,001	1,395,891	7,148,771	5.2660
65			79,332					Gas MCF ->	861,867	1,000,000	861,867	6,713,986	8.4631
67	MARTIN 3	465	252,761	80.9	95.1	89.0	7,117	Gas MCF ->	1,798,872	1,000,000	1,798,872	14,028,815	5.5502
69	MARTIN 4	466	230,290	73.5	84.4	82.7	6,935	Gas MCF ->	1,597,095	1,000,000	1,597,095	12,459,263	5.4103
71	MARTIN 8	1,099		0.0	0.0		0						
73	FM GT	624	5,071	1.2	90.2	44.4	16,320	Light Oil BBLS ->	14,194	5,830,020	82,751	800,800	15.7927
75	FL GT	768	1	0.7	91.7	27.5	19,253	Light Oil BBLS ->	2	5,950,000	12	100	14.2857
76			3,581					Gas MCF ->	68,936	1,000,000	68,936	536,957	14.9967
78	PE GT	384	0	1.4	88.3	54.9	17,863	Light Oil BBLS ->	0		0	0	
79			3,571					Gas MCF ->	63,784	1,000,000	63,784	496,849	13.9146
81	SJRPP 1O	130	72,239	82.7	86.5	99.6	9,639	Coal TONS ->	28,467	24,459,950	696,301	1,106,300	1.5314
83	SJRPP 2O	130	77,637	88.9	93.6	99.7	9,499	Coal TONS ->	30,151	24,459,963	737,495	1,171,800	1.5093
85	SCHER #4	648	347,975	79.9	94.2	89.8	9,825	Coal TONS ->	195,364	17,500,001	3,418,861	5,428,900	1.5601
87	FMREP 1	1,451	723,542	74.2	82.9	84.3	6,920	Gas MCF ->	5,007,216	1,000,000	5,007,216	39,003,902	5.3907
89	SNREP4	938	472,004	74.9	88.9	84.3	6,982	Gas MCF ->	3,295,762	1,000,000	3,295,762	25,721,806	5.4495
91	SNREP5	938	483,104	76.6	95.2	87.5	6,841	Gas MCF ->	3,304,830	1,000,000	3,304,830	25,842,009	5.3492
93	MANATE 3	1,105		0.0	0.0		0						

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	FM SC	166	40,194	18.0	91.9	86.3	10,926	Gas MCF ->	439,168	1,000,000	439,168	3,463,530	8.6171
96													
97	MR SC	163		0.0	0.0		0						
98													
99	TOTAL	13,196	3,188,972	0.0			7,983				25,459,035	160,297,047	5.0266

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	117,209	45.4	95.0	88.3	8,951	Heavy Oil BBLS ->	158,333	6,399,998	1,013,330	5,123,143	4.3709
2			16,861					Gas MCF ->	186,722	1,000,000	186,722	1,430,373	8.4832
3													
4	TRKY O 2	397		0.0	0.0		0						
5													
6	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,912,000	0.3676
7													
8	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,580,300	0.3038
9													
10	FT LAUD4	443	166,797	50.6	58.0	92.0	7,711	Gas MCF ->	1,286,135	1,000,000	1,286,135	9,852,575	5.9069
11													
12	FT LAUD5	442	279,836	85.1	93.6	89.8	7,847	Gas MCF ->	2,195,919	1,000,000	2,195,919	16,822,021	6.0114
13													
14	PT EVER1	211	8,202	10.9	95.0	57.4	11,037	Heavy Oil BBLS ->	10,492	6,400,013	67,148	339,938	4.1447
15			8,967					Gas MCF ->	122,352	1,000,000	122,352	937,309	10.4524
16													
17	PT EVER2	211		0.0	0.0		0						
18													
19	PT EVER3	383	65,682	28.4	95.1	72.6	10,496	Heavy Oil BBLS ->	101,499	6,400,003	649,593	3,288,263	5.0064
20			15,242					Gas MCF ->	199,774	1,000,000	199,774	1,530,425	10.0408
21													
22	PT EVER4	390	38,117	18.4	95.6	59.1	11,688	Heavy Oil BBLS ->	63,286	6,399,999	405,031	2,050,318	5.3790
23			15,199					Gas MCF ->	218,127	1,000,000	218,127	1,671,042	10.9944
24													
25	RIV 3	275	1,460	1.7	33.3	42.7	13,664	Heavy Oil BBLS ->	2,056	6,400,029	13,156	66,449	4.5528
26			2,095					Gas MCF ->	35,419	1,000,000	35,419	271,322	12.9491
27													
28	RIV 4	281	138,405	74.0	92.8	83.0	9,012	Heavy Oil BBLS ->	193,154	6,399,999	1,236,186	6,242,972	4.5106
29			16,291					Gas MCF ->	157,936	1,000,000	157,936	1,209,860	7.4264
30													

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	853	618,763	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,709,888	1,000,000	6,709,888	1,902,500	0.3075
33	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,752,800	0.3329
35	CAP CN 1	398		0.0	0.0		0						
37	CAP CN 2	398	96,907	38.0	94.7	83.3	9,658	Heavy Oil BBLS ->	140,686	6,400,000	900,391	4,545,084	4.6902
38			15,623					Gas MCF ->	186,384	1,000,000	186,384	1,427,807	9.1394
40	SANFRD 3	140	531	1.5	34.0	43.1	12,935	Heavy Oil BBLS ->	748	6,400,027	4,785	21,181	3.9897
41			1,052					Gas MCF ->	15,684	1,000,000	15,684	120,120	11.4226
43	PUTNAM 1	250	17,869	9.6	64.5	49.6	9,607	Gas MCF ->	171,671	1,000,000	171,671	1,315,250	7.3605
45	PUTNAM 2	250	25,211	13.6	95.4	68.3	9,135	Gas MCF ->	230,307	1,000,000	230,307	1,764,409	6.9985
47	MANATE 1	821	224,316	38.9	94.4	73.2	10,019	Heavy Oil BBLS ->	348,986	6,399,999	2,233,508	11,261,577	5.0204
48			13,366					Gas MCF ->	147,821	1,000,000	147,821	1,174,215	8.7850
50	MANATE 2	821	168,863	30.5	95.8	66.7	10,578	Heavy Oil BBLS ->	276,178	6,400,001	1,767,541	8,912,097	5.2777
51			17,734					Gas MCF ->	206,225	1,000,000	206,225	1,637,992	9.2363
53	CUTLER 5	70	2,746	5.3	97.6	47.8	12,088	Gas MCF ->	33,190	1,000,000	33,190	254,271	9.2611
55	CUTLER 6	142	6,173	5.8	96.6	49.0	10,865	Gas MCF ->	67,073	1,000,000	67,073	513,887	8.3246
57	MARTIN 1	813		0.0	0.0		0						
59	MARTIN 2	804	187,675	48.3	96.3	72.4	10,426	Heavy Oil BBLS ->	299,939	6,400,000	1,919,608	9,726,803	5.1828
60			101,347					Gas MCF ->	1,093,783	1,000,000	1,093,783	8,378,980	8.2676

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 3	465	251,923	72.8	85.9	82.8	7,149	Gas MCF ->	1,800,915	1,000,000	1,800,915	13,796,040	5.4763
64	MARTIN 4	466	229,422	66.2	76.3	74.9	7,006	Gas MCF ->	1,607,315	1,000,000	1,607,315	12,312,965	5.3669
66	MARTIN 8	1,099		0.0	0.0		0						
68	FM GT	624	1,807	0.4	89.1	86.3	12,432	Light Oil BBLS ->	3,854	5,830,042	22,468	217,400	12.0290
70	FL GT	768	138	0.1	91.7	90.3	13,998	Light Oil BBLS ->	320	5,830,053	1,866	12,800	9.2552
71			415					Gas MCF ->	5,878	1,000,000	5,878	45,018	10.8502
73	PE GT	384	17	0.0	88.3	93.1	14,388	Light Oil BBLS ->	41	5,835,381	238	1,700	9.9415
74			51					Gas MCF ->	748	1,000,000	748	5,688	11.0653
76	SJRPP 1O	130		0.0	0.0		0						
78	SJRPP 2O	130	87,134	90.1	93.6	99.8	9,498	Coal TONS ->	33,837	24,459,590	827,637	1,309,800	1.5032
80	SCHER #4	648	390,485	81.0	94.2	89.9	9,825	Coal TONS ->	219,219	17,499,997	3,836,327	6,102,900	1.5629
82	FMREP 1	1,451	865,240	80.1	94.7	89.6	6,882	Gas MCF ->	5,954,284	1,000,000	5,954,284	45,613,362	5.2718
84	SNREP4	938	561,668	80.5	95.7	90.0	6,901	Gas MCF ->	3,876,101	1,000,000	3,876,101	29,693,225	5.2866
86	SNREP5	938	539,723	77.3	95.2	88.3	6,818	Gas MCF ->	3,679,920	1,000,000	3,679,920	28,204,322	5.2257
88	MANATE 3	1,105		0.0	0.0		0						
90	FM SC	166	29,814	12.1	83.0	87.3	10,926	Gas MCF ->	325,758	1,000,000	325,758	2,497,287	8.3762

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	MR SC	163		0.0	0.0		0						
93													
94	TOTAL	13,446	3,723,137	0.0			8,007				29,810,181	184,751,987	4.9623

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Estimated For The Period of : Apr-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	43,897	17.5	95.0	74.0	10,059	Heavy Oil BBLS ->	65,603	6,399,999	419,860	2,114,718	4.8175
2			5,827					Gas MCF ->	80,304	1,000,000	80,304	573,628	9.8436
3													
4	TRKY O 2	394		0.0	0.0		0						
5													
6	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,825,800	0.3753
7													
8	TRKY N 4	693	129,730	26.0	26.0	100.0	11,485	Nuclear Othr ->	1,489,945	1,000,000	1,489,945	402,400	0.3102
9													
10	FT LAUD4	425	275,838	90.1	94.7	95.2	7,620	Gas MCF ->	2,101,941	1,000,000	2,101,941	15,013,113	5.4427
11													
12	FT LAUD5	424	272,338	89.2	93.6	94.2	7,306	Gas MCF ->	1,989,709	1,000,000	1,989,709	14,211,548	5.2183
13													
14	PT EVER1	210	6,739	5.2	95.0	78.2	10,487	Heavy Oil BBLS ->	10,211	6,400,022	65,349	325,963	4.8368
15			1,078					Gas MCF ->	16,637	1,000,000	16,637	118,819	11.0191
16													
17	PT EVER2	210		0.0	0.0		0						
18													
19	PT EVER3	381	81,100	33.0	95.1	82.1	9,439	Heavy Oil BBLS ->	115,606	6,400,002	739,880	3,690,947	4.5511
20			9,307					Gas MCF ->	113,511	1,000,000	113,511	810,805	8.7115
21													
22	PT EVER4	388	96,424	39.1	95.6	87.3	9,295	Heavy Oil BBLS ->	135,952	6,400,001	870,090	4,340,473	4.5015
23			12,935					Gas MCF ->	146,376	1,000,000	146,376	1,045,478	8.0823
24													
25	RIV 3	273	81,718	50.5	68.8	84.6	10,384	Heavy Oil BBLS ->	130,929	6,400,000	837,944	4,192,141	5.1300
26			17,543					Gas MCF ->	192,778	1,000,000	192,778	1,376,909	7.8489
27													
28	RIV 4	279	11,614	6.5	92.8	79.4	10,615	Heavy Oil BBLS ->	17,912	6,399,982	114,635	573,559	4.9386
29			1,492					Gas MCF ->	24,480	1,000,000	24,480	174,904	11.7228
30													

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Estimated For The Period of : Apr-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,838,000	0.3121
33	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,693,400	0.3379
35	CAP CN 1	394	54,654	22.0	91.0	78.0	9,760	Heavy Oil BBLS ->	79,669	6,400,003	509,883	2,549,729	4.6652
36			7,889					Gas MCF ->	100,518	1,000,000	100,518	717,932	9.1010
38	CAP CN 2	394	71,026	28.0	94.7	81.2	9,350	Heavy Oil BBLS ->	99,984	6,400,001	639,900	3,199,956	4.5053
39			8,515					Gas MCF ->	103,798	1,000,000	103,798	741,354	8.7060
41	SANFRD 3	138	6,542	8.2	92.6	72.7	9,816	Heavy Oil BBLS ->	9,029	6,400,013	57,787	255,779	3.9097
42			1,593					Gas MCF ->	22,071	1,000,000	22,071	157,659	9.8951
44	PUTNAM 1	239	15,911	9.2	71.5	63.1	8,887	Gas MCF ->	141,403	1,000,000	141,403	1,009,948	6.3474
46	PUTNAM 2	239	14,947	8.7	81.1	70.8	8,962	Gas MCF ->	133,961	1,000,000	133,961	956,820	6.4015
48	MANATE 1	795	259,918	48.9	94.4	69.1	10,048	Heavy Oil BBLS ->	406,388	6,400,000	2,600,885	12,934,639	4.9764
49			20,120					Gas MCF ->	213,016	1,000,000	213,016	1,586,034	7.8828
51	MANATE 2	795	233,104	43.9	95.8	71.1	10,104	Heavy Oil BBLS ->	366,020	6,399,999	2,342,527	11,649,782	4.9977
52			17,915					Gas MCF ->	193,879	1,000,000	193,879	1,442,489	8.0520
54	CUTLER 5	68	1,618	3.3	97.6	78.4	11,439	Gas MCF ->	18,512	1,000,000	18,512	132,189	8.1684
56	CUTLER 6	138	3,712	3.7	96.6	75.8	11,842	Gas MCF ->	43,959	1,000,000	43,959	313,955	8.4576
58	MARTIN 1	803	210,955	56.6	92.7	71.5	10,676	Heavy Oil BBLS ->	345,614	6,400,001	2,211,931	11,013,456	5.2208
59			116,018					Gas MCF ->	1,278,750	1,000,000	1,278,750	9,133,492	7.8725

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Estimated For The Period of : Apr-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 2	796	249,123	69.0	96.3	71.6	10,475	Heavy Oil BBLS ->	400,352	6,400,000	2,562,255	12,757,820	5.1211
62			146,139					Gas MCF ->	1,578,200	1,000,000	1,578,200	11,272,314	7.7134
64	MARTIN 3	443	239,681	75.1	95.1	83.8	7,198	Gas MCF ->	1,725,171	1,000,000	1,725,171	12,322,022	5.1410
66	MARTIN 4	443	256,383	80.4	94.6	93.5	6,971	Gas MCF ->	1,787,353	1,000,000	1,787,353	12,766,208	4.9794
68	MARTIN 8	1,080		0.0	0.0		0						
70	FM GT	552	407	0.1	90.7	92.6	11,467	Light Oil BBLS ->	800	5,830,064	4,666	45,000	11.0592
72	FL GT	684	33	0.0	91.7	89.7	14,019	Light Oil BBLS ->	77	5,826,371	446	3,100	9.3939
73			99					Gas MCF ->	1,406	1,000,000	1,406	10,052	10.1435
75	PE GT	348	3	0.0	88.3	92.0	15,348	Light Oil BBLS ->	8	5,846,154	46	300	9.6774
76			9					Gas MCF ->	144	1,000,000	144	1,028	11.1729
78	SJRPP 1O	127	2,774	3.0	12.4	97.7	9,503	Coal TONS ->	1,078	24,456,207	26,359	41,600	1.4997
80	SJRPP 2O	127	81,754	89.4	93.6	99.7	9,321	Coal TONS ->	31,160	24,455,948	762,045	1,205,200	1.4742
82	SCHER #4	643	374,788	81.0	94.2	90.0	9,599	Coal TONS ->	205,578	17,500,005	3,597,607	5,727,600	1.5282
84	FMREP 1	1,423	868,202	84.7	94.7	94.0	6,932	Gas MCF ->	6,018,456	1,000,000	6,018,456	42,986,880	4.9513
86	SNREP4	891	523,430	81.6	95.7	93.9	6,935	Gas MCF ->	3,629,836	1,000,000	3,629,836	25,926,120	4.9531
88	SNREP5	940	538,392	79.5	95.2	91.0	6,880	Gas MCF ->	3,704,260	1,000,000	3,704,260	26,457,710	4.9142
90	MANATE 3	1,080		0.0	0.0		0						

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	FM SC	164	7,874	3.3	97.1	91.3	10,584	Gas MCF ->	83,341	1,000,000	83,341	595,232	7.5596
93													
94	MR SC	149		0.0	0.0		0						
95													
96	TOTAL	12,967	4,183,308	0.0			8,285				34,660,412	202,290,990	4.8357

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Estimated For The Period of : May-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	85,254	31.4	95.0	78.4	9,864	Heavy Oil BBLS ->	126,916	6,400,001	812,261	4,074,848	4.7796
2			6,667					Gas MCF ->	94,417	1,000,000	94,417	651,052	9.7651
3													
4	TRKY O 2	394	42,935	16.2	60.5	78.5	9,838	Heavy Oil BBLS ->	63,651	6,399,996	407,364	2,043,619	4.7599
5			4,657					Gas MCF ->	60,840	1,000,000	60,840	419,528	9.0085
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,883,100	0.3746
8													
9	TRKY N 4	693		0.0	0.0		0						
10													
11	FT LAUD4	425	293,519	92.8	94.7	98.0	7,534	Gas MCF ->	2,211,250	1,000,000	2,211,250	15,247,943	5.1949
12													
13	FT LAUD5	424	291,731	92.5	93.6	97.6	7,239	Gas MCF ->	2,111,935	1,000,000	2,111,935	14,563,020	4.9919
14													
15	PT EVER1	210	29,418	21.2	95.0	77.0	10,337	Heavy Oil BBLS ->	44,648	6,400,003	285,749	1,423,321	4.8383
16			3,713					Gas MCF ->	56,733	1,000,000	56,733	391,298	10.5375
17													
18	PT EVER2	210	8,135	5.8	39.6	76.1	10,219	Heavy Oil BBLS ->	11,874	6,400,017	75,994	378,486	4.6528
19			1,001					Gas MCF ->	17,359	1,000,000	17,359	119,675	11.9603
20													
21	PT EVER3	381	119,936	46.5	95.1	85.8	9,356	Heavy Oil BBLS ->	170,597	6,400,001	1,091,818	5,438,394	4.5344
22			11,784					Gas MCF ->	140,603	1,000,000	140,603	969,499	8.2270
23													
24	PT EVER4	388	133,516	51.9	95.6	90.8	9,256	Heavy Oil BBLS ->	188,118	6,399,999	1,203,956	5,996,932	4.4915
25			16,194					Gas MCF ->	181,726	1,000,000	181,726	1,253,140	7.7382
26													
27	RIV 3	273	31,517	17.8	93.8	74.7	10,979	Heavy Oil BBLS ->	50,555	6,400,002	323,550	1,614,565	5.1228
28			4,548					Gas MCF ->	72,406	1,000,000	72,406	499,305	10.9786
29													
30	RIV 4	279	131,735	77.7	92.8	87.4	10,021	Heavy Oil BBLS ->	203,577	6,400,000	1,302,891	6,501,823	4.9355
31			29,453					Gas MCF ->	312,297	1,000,000	312,297	2,153,505	7.3118
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,895,600	0.3115
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,746,500	0.3372
37	CAP CN 1	394	102,911	38.6	94.2	83.5	9,568	Heavy Oil BBLS ->	149,488	6,399,998	956,723	4,766,552	4.6317
38			10,176					Gas MCF ->	125,256	1,000,000	125,256	863,755	8.4884
40	CAP CN 2	394	115,351	43.2	94.7	85.2	9,243	Heavy Oil BBLS ->	162,057	6,400,000	1,037,164	5,167,320	4.4796
41			11,346					Gas MCF ->	133,934	1,000,000	133,934	923,591	8.1405
43	SANFRD 3	138	19,650	22.7	95.8	78.1	9,449	Heavy Oil BBLS ->	26,947	6,399,992	172,463	762,888	3.8823
44			3,685					Gas MCF ->	48,022	1,000,000	48,022	331,135	8.9870
46	PUTNAM 1	239	227	26.3	95.3	81.9	8,617	Light Oil BBLS ->	320	5,829,169	1,867	14,600	6.4204
47			46,470					Gas MCF ->	400,521	1,000,000	400,521	2,763,336	5.9465
49	PUTNAM 2	239	198	21.1	32.3	75.6	9,087	Light Oil BBLS ->	294	5,830,048	1,715	13,400	6.7643
50			37,239					Gas MCF ->	338,490	1,000,000	338,490	2,335,542	6.2717
52	MANATE 1	795	388,647	69.2	94.4	75.8	9,994	Heavy Oil BBLS ->	605,117	6,400,000	3,872,748	19,223,518	4.9463
53			20,477					Gas MCF ->	215,860	1,000,000	215,860	1,586,315	7.7470
55	MANATE 2	795	391,124	70.3	95.8	73.8	10,061	Heavy Oil BBLS ->	613,027	6,400,001	3,923,376	19,474,809	4.9792
56			24,749					Gas MCF ->	260,671	1,000,000	260,671	1,916,548	7.7439
58	CUTLER 5	68	6,007	11.9	97.6	68.3	11,632	Gas MCF ->	69,874	1,000,000	69,874	481,853	8.0217
60	CUTLER 6	138	12,898	12.6	96.6	66.5	12,032	Gas MCF ->	155,185	1,000,000	155,185	1,070,121	8.2969
62	MARTIN 1	803	284,350	72.5	95.9	75.2	10,643	Heavy Oil BBLS ->	464,854	6,400,000	2,975,068	14,800,623	5.2051
63			148,985					Gas MCF ->	1,636,720	1,000,000	1,636,720	11,286,124	7.5754

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	282,105	74.5	96.3	77.3	10,449	Heavy Oil BBLS ->	452,427	6,399,999	2,895,530	14,404,851	5.1062
66			158,988					Gas MCF ->	1,713,451	1,000,000	1,713,451	11,815,236	7.4315
68	MARTIN 3	443	283,281	85.9	95.1	95.3	7,095	Gas MCF ->	2,009,774	1,000,000	2,009,774	13,858,590	4.8922
70	MARTIN 4	443	281,279	85.3	94.6	95.9	6,947	Gas MCF ->	1,953,976	1,000,000	1,953,976	13,473,850	4.7902
72	MARTIN 8	1,080	6,373	0.8	1.0	55.9	6,989	Gas MCF ->	44,541	1,000,000	44,541	307,113	4.8190
74	FM GT	552	11,337	2.8	98.4	58.4	14,049	Light Oil BBLS ->	27,320	5,829,997	159,273	1,526,300	13.4629
76	FL GT	684	231	1.5	91.7	35.8	18,205	Light Oil BBLS ->	687	5,830,180	4,007	27,400	11.8718
77			7,515					Gas MCF ->	137,003	1,000,000	137,003	945,079	12.5762
79	PE GT	348	42	2.6	88.3	62.5	18,390	Light Oil BBLS ->	126	5,830,159	735	5,300	12.6492
80			6,461					Gas MCF ->	118,860	1,000,000	118,860	819,870	12.6891
82	SJRPP 1O	127	84,005	88.9	93.1	99.7	9,460	Coal TONS ->	32,497	24,455,575	794,726	1,256,100	1.4953
84	SJRPP 2O	127	84,580	89.5	93.6	99.7	9,323	Coal TONS ->	32,242	24,455,591	788,505	1,246,300	1.4735
86	SCHER #4	643	385,660	80.6	94.2	90.0	9,599	Coal TONS ->	211,539	17,500,004	3,701,933	5,895,700	1.5287
88	FMREP 1	1,423	928,922	87.7	94.7	96.8	6,903	Gas MCF ->	6,412,056	1,000,000	6,412,056	44,214,983	4.7598
90	SNREP4	891	569,331	85.9	95.7	97.5	6,881	Gas MCF ->	3,917,689	1,000,000	3,917,689	27,062,594	4.7534
92	SNREP5	940	525,935	75.2	84.5	85.4	6,916	Gas MCF ->	3,637,421	1,000,000	3,637,421	25,230,458	4.7973
94	MANATE 3	1,080		0.0	0.0		0						

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	4,591	18.3	97.1	90.5	10,526	Light Oil BBLS ->	7,933	5,829,987	46,249	443,200	9.6537
97			40,034					Gas MCF ->	423,463	1,000,000	423,463	2,973,136	7.4265
98													
99	MR SC	149		0.0	0.0		0						
100													
101	TOTAL	12,728	4,975,342	0.0			8,484				42,208,895	237,694,913	4.7775

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	76,652	29.5	95.0	79.1	9,920	Heavy Oil BBLS ->	114,076	6,399,998	730,088	3,663,639	4.7796
2			6,993					Gas MCF ->	99,640	1,000,000	99,640	690,407	9.8724
3													
4	TRKY O 2	394	87,849	34.0	93.7	83.0	9,797	Heavy Oil BBLS ->	129,795	6,400,001	830,690	4,168,445	4.7450
5			8,509					Gas MCF ->	113,377	1,000,000	113,377	785,640	9.2327
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,819,000	0.3739
8													
9	TRKY N 4	693	291,892	58.5	58.5	100.0	11,485	Nuclear Othr ->	3,352,356	1,000,000	3,352,356	1,112,300	0.3811
10													
11	FT LAUD4	425	280,398	91.6	94.7	96.7	7,589	Gas MCF ->	2,127,971	1,000,000	2,127,971	14,745,266	5.2587
12													
13	FT LAUD5	424	276,518	90.6	93.6	95.6	7,302	Gas MCF ->	2,019,036	1,000,000	2,019,036	13,990,390	5.0595
14													
15	PT EVER1	210	7,145	6.3	95.0	57.3	11,980	Heavy Oil BBLS ->	11,148	6,400,027	71,344	356,437	4.9888
16			2,452					Gas MCF ->	43,626	1,000,000	43,626	302,293	12.3284
17													
18	PT EVER2	210	13,931	11.2	94.4	66.7	10,702	Heavy Oil BBLS ->	20,565	6,400,010	131,613	657,461	4.7194
19			2,971					Gas MCF ->	49,273	1,000,000	49,273	341,452	11.4936
20													
21	PT EVER3	381	113,209	44.8	95.1	86.6	9,350	Heavy Oil BBLS ->	160,868	6,399,998	1,029,552	5,142,976	4.5429
22			9,593					Gas MCF ->	118,664	1,000,000	118,664	822,303	8.5718
23													
24	PT EVER4	388	121,428	48.3	95.6	90.4	9,265	Heavy Oil BBLS ->	171,072	6,399,999	1,094,862	5,469,161	4.5040
25			13,452					Gas MCF ->	154,837	1,000,000	154,837	1,072,847	7.9753
26													
27	RIV 3	273	118,574	75.5	93.8	83.8	10,418	Heavy Oil BBLS ->	190,462	6,400,000	1,218,956	6,098,281	5.1430
28			29,801					Gas MCF ->	326,869	1,000,000	326,869	2,264,781	7.5997
29													
30	RIV 4	279	11,036	6.9	92.8	61.2	11,936	Heavy Oil BBLS ->	17,374	6,400,010	111,193	556,323	5.0412
31			2,912					Gas MCF ->	55,279	1,000,000	55,279	381,907	13.1154
32													

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Estimated For The Period of : Jun-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,831,100	0.3109
35	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,687,100	0.3366
37	CAP CN 1	394	104,587	39.8	94.2	85.4	9,555	Heavy Oil BBLS ->	151,702	6,400,001	970,892	4,845,939	4.6334
38			8,433					Gas MCF ->	109,019	1,000,000	109,019	755,445	8.9582
40	CAP CN 2	394	114,209	43.3	94.7	86.9	9,228	Heavy Oil BBLS ->	160,209	6,400,000	1,025,340	5,117,709	4.4810
41			8,679					Gas MCF ->	108,634	1,000,000	108,634	752,728	8.6730
43	SANFRD 3	138	9,808	12.9	95.8	68.2	10,141	Heavy Oil BBLS ->	13,640	6,399,981	87,298	385,811	3.9336
44			3,039					Gas MCF ->	42,991	1,000,000	42,991	297,270	9.7812
46	PUTNAM 1	239	40,889	23.8	95.3	80.2	8,737	Gas MCF ->	357,243	1,000,000	357,243	2,475,441	6.0540
48	PUTNAM 2	239	26,962	15.7	95.4	71.5	9,223	Gas MCF ->	248,657	1,000,000	248,657	1,723,053	6.3907
50	MANATE 1	795	280,209	53.6	94.4	68.7	10,096	Heavy Oil BBLS ->	439,658	6,400,000	2,813,811	14,014,897	5.0016
51			26,503					Gas MCF ->	282,678	1,000,000	282,678	1,945,821	7.3419
53	MANATE 2	795	216,201	41.4	95.8	67.4	10,139	Heavy Oil BBLS ->	340,331	6,400,000	2,178,120	10,848,613	5.0178
54			20,877					Gas MCF ->	225,691	1,000,000	225,691	1,553,605	7.4417
56	CUTLER 5	68	1,667	3.4	97.6	52.1	14,134	Gas MCF ->	23,554	1,000,000	23,554	162,933	9.7770
58	CUTLER 6	138	4,370	4.4	96.6	54.8	12,775	Gas MCF ->	55,831	1,000,000	55,831	386,663	8.8475
60	MARTIN 1	803	201,749	55.2	95.9	68.4	10,742	Heavy Oil BBLS ->	332,245	6,400,001	2,126,365	10,624,421	5.2662
61			117,232					Gas MCF ->	1,300,243	1,000,000	1,300,243	8,950,056	7.6345

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Estimated For The Period of : Jun-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	796	227,731	63.6	96.3	70.2	10,494	Heavy Oil BBLS ->	366,401	6,400,000	2,344,966	11,716,696	5.1450
64			136,944					Gas MCF ->	1,481,961	1,000,000	1,481,961	10,200,981	7.4490
66	MARTIN 3	443	260,925	81.8	95.1	92.2	7,148	Gas MCF ->	1,865,036	1,000,000	1,865,036	12,837,834	4.9201
68	MARTIN 4	443	261,790	82.1	94.6	94.1	6,982	Gas MCF ->	1,827,710	1,000,000	1,827,710	12,580,939	4.8057
70	MARTIN 8	1,080	613,784	78.9	96.5	92.6	6,883	Gas MCF ->	4,224,857	1,000,000	4,224,857	29,122,886	4.7448
72	FM GT	552	1,569	0.4	98.4	93.6	11,467	Light Oil BBLS ->	3,085	5,830,033	17,987	172,200	10.9772
74	FL GT	684	154	0.1	91.7	92.1	14,018	Light Oil BBLS ->	357	5,830,020	2,082	14,200	9.2148
75			462					Gas MCF ->	6,558	1,000,000	6,558	45,410	9.8227
77	PE GT	348	23	0.0	88.3	94.3	15,348	Light Oil BBLS ->	58	5,832,180	337	2,400	10.5263
78			68					Gas MCF ->	1,062	1,000,000	1,062	7,376	10.7838
80	SJRPP 1O	127	81,960	89.6	93.1	99.7	9,459	Coal TONS ->	31,701	24,455,202	775,262	1,225,000	1.4946
82	SJRPP 2O	127	82,778	90.5	93.6	99.7	9,321	Coal TONS ->	31,551	24,455,171	771,585	1,219,200	1.4729
84	SCHER #4	643	375,494	81.1	94.2	89.8	9,599	Coal TONS ->	205,963	17,500,002	3,604,358	5,741,200	1.5290
86	FMREP 1	1,423	868,081	84.7	94.7	94.7	6,922	Gas MCF ->	6,008,992	1,000,000	6,008,992	41,637,774	4.7965
88	SNREP4	891	536,418	83.6	95.7	96.6	6,889	Gas MCF ->	3,695,358	1,000,000	3,695,358	25,606,027	4.7735
90	SNREP5	940	500,741	74.0	82.5	86.0	6,915	Gas MCF ->	3,462,763	1,000,000	3,462,763	23,994,326	4.7918
92	MANATE 3	1,080	597,986	76.9	96.5	91.0	6,820	Gas MCF ->	4,078,383	1,000,000	4,078,383	30,019,839	5.0202

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	164	22,304	9.4	97.1	86.9	10,566	Gas	MCF ->	235,673	1,000,000	235,673	1,633,040	7.3217
95														
96	MR SC	149		0.0	0.0		0							
97														
98	TOTAL	20,210	8,806,630	0.0			8,817					77,647,212	340,577,244	3.8673

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Estimated For The Period of : Jul-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	83,768	33.9	95.0	69.1	10,020	Heavy Oil BBLS ->	126,628	6,400,002	810,419	4,073,915	4.8634
2			15,698					Gas MCF ->	186,193	1,000,000	186,193	1,278,282	8.1431
3													
4	TRKY O 2	394	88,228	38.8	93.7	74.8	9,960	Heavy Oil BBLS ->	132,657	6,399,999	849,004	4,267,863	4.8373
5			25,603					Gas MCF ->	284,691	1,000,000	284,691	1,954,482	7.6339
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,882,600	0.3745
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,914,000	0.3807
10													
11	FT LAUD4	425	290,097	91.7	94.7	96.9	7,650	Gas MCF ->	2,219,162	1,000,000	2,219,162	15,235,007	5.2517
12													
13	FT LAUD5	424	286,572	90.8	93.6	95.9	7,361	Gas MCF ->	2,109,514	1,000,000	2,109,514	14,482,235	5.0536
14													
15	PT EVER1	210	16,157	14.8	95.0	45.8	11,516	Heavy Oil BBLS ->	25,694	6,400,007	164,441	824,202	5.1013
16			6,894					Gas MCF ->	101,018	1,000,000	101,018	693,425	10.0588
17													
18	PT EVER2	210	22,379	19.3	94.4	54.2	10,721	Heavy Oil BBLS ->	33,667	6,399,999	215,471	1,080,037	4.8262
19			7,835					Gas MCF ->	108,448	1,000,000	108,448	744,503	9.5018
20													
21	PT EVER3	381	118,641	49.5	95.1	84.4	9,440	Heavy Oil BBLS ->	170,451	6,400,001	1,090,883	5,467,959	4.6088
22			21,797					Gas MCF ->	234,791	1,000,000	234,791	1,611,960	7.3955
23													
24	PT EVER4	388	123,921	51.5	95.6	86.4	9,364	Heavy Oil BBLS ->	176,626	6,400,001	1,130,408	5,665,999	4.5723
25			24,861					Gas MCF ->	262,856	1,000,000	262,856	1,804,576	7.2586
26													
27	RIV 3	273	6,822	8.1	93.8	28.3	14,162	Heavy Oil BBLS ->	12,466	6,399,986	79,780	400,173	5.8663
28			9,699					Gas MCF ->	154,179	1,000,000	154,179	1,056,907	10.8971
29													
30	RIV 4	279	92,752	76.0	92.8	85.1	10,290	Heavy Oil BBLS ->	145,650	6,399,999	932,160	4,675,206	5.0405
31			64,976					Gas MCF ->	690,817	1,000,000	690,817	4,742,369	7.2986
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,888,500	0.3103
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,745,200	0.3370
37	CAP CN 1	394	95,086	45.0	94.2	82.0	9,741	Heavy Oil BBLS ->	140,054	6,400,000	896,346	4,485,432	4.7172
38			36,958					Gas MCF ->	389,953	1,000,000	389,953	2,677,079	7.2435
40	CAP CN 2	394	112,724	48.7	94.7	84.7	9,329	Heavy Oil BBLS ->	159,647	6,399,998	1,021,737	5,112,889	4.5358
41			30,166					Gas MCF ->	311,231	1,000,000	311,231	2,136,594	7.0829
43	SANFRD 3	138	14,892	20.6	95.8	57.9	10,004	Heavy Oil BBLS ->	21,134	6,400,008	135,258	600,967	4.0355
44			6,300					Gas MCF ->	76,750	1,000,000	76,750	526,157	8.3524
46	PUTNAM 1	239	55,368	31.1	95.3	74.4	9,021	Gas MCF ->	499,469	1,000,000	499,469	3,428,956	6.1930
48	PUTNAM 2	239	39,618	22.3	95.4	64.4	9,641	Gas MCF ->	381,977	1,000,000	381,977	2,622,306	6.6189
50	MANATE 1	795	264,285	50.6	94.4	57.1	10,201	Heavy Oil BBLS ->	418,583	6,400,000	2,678,930	13,385,088	5.0646
51			34,937					Gas MCF ->	373,463	1,000,000	373,463	2,546,542	7.2889
53	MANATE 2	795	194,253	39.1	95.8	50.0	10,356	Heavy Oil BBLS ->	311,404	6,399,999	1,992,985	9,957,839	5.1262
54			37,203					Gas MCF ->	404,009	1,000,000	404,009	2,754,954	7.4052
56	CUTLER 5	68	4,539	9.0	97.6	31.5	13,773	Gas MCF ->	62,510	1,000,000	62,510	428,650	9.4443
58	CUTLER 6	138	9,482	9.2	96.6	32.0	13,238	Gas MCF ->	125,527	1,000,000	125,527	861,367	9.0838
60	MARTIN 1	803	201,823	56.1	95.9	58.2	10,954	Heavy Oil BBLS ->	338,708	6,400,001	2,167,730	10,870,946	5.3864
61			133,307					Gas MCF ->	1,503,408	1,000,000	1,503,408	10,251,687	7.6903

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	796	193,256	58.1	96.3	60.4	10,686	Heavy Oil BBLS ->	315,757	6,400,001	2,020,847	10,134,285	5.2440
64			151,050					Gas MCF ->	1,658,473	1,000,000	1,658,473	11,309,136	7.4870
66	MARTIN 3	443	275,210	83.5	95.1	91.7	7,178	Gas MCF ->	1,975,360	1,000,000	1,975,360	13,469,924	4.8944
68	MARTIN 4	443	270,613	82.1	94.6	92.9	7,022	Gas MCF ->	1,900,139	1,000,000	1,900,139	12,957,073	4.7880
70	MARTIN 8	1,080	632,468	78.7	96.6	89.5	6,994	Gas MCF ->	4,423,391	1,000,000	4,423,391	30,227,705	4.7793
72	FM GT	552	43,123	10.5	98.4	51.0	14,853	Light Oil BBLS ->	109,866	5,829,998	640,519	6,023,600	13.9686
74	FL GT	684	90	6.3	91.7	31.2	19,050	Light Oil BBLS ->	280	5,830,418	1,633	11,200	12.4444
75			32,099					Gas MCF ->	611,553	1,000,000	611,553	4,198,391	13.0796
77	PE GT	348	14	12.4	88.3	61.5	18,479	Light Oil BBLS ->	42	5,830,952	245	1,800	12.9496
78			31,579					Gas MCF ->	583,575	1,000,000	583,575	4,006,338	12.6866
80	SJRPP 1O	127	83,320	88.2	93.1	98.3	9,476	Coal TONS ->	32,291	24,451,621	789,572	1,250,100	1.5004
82	SJRPP 2O	127	83,984	88.9	93.6	98.4	9,338	Coal TONS ->	32,074	24,451,591	784,258	1,241,700	1.4785
84	SCHER #4	643	382,204	79.9	94.2	88.7	9,607	Coal TONS ->	209,828	17,500,006	3,671,998	5,849,300	1.5304
86	FMREP 1	1,423	888,753	83.9	94.7	94.4	6,944	Gas MCF ->	6,171,784	1,000,000	6,171,784	42,370,532	4.7674
88	SNREP4	891	546,934	82.5	95.7	93.4	6,961	Gas MCF ->	3,807,481	1,000,000	3,807,481	26,139,060	4.7792
90	SNREP5	940	550,733	78.7	95.2	89.2	6,920	Gas MCF ->	3,811,164	1,000,000	3,811,164	26,164,426	4.7508
92	MANATE 3	1,080	622,043	77.4	96.6	87.5	6,929	Gas MCF ->	4,310,272	1,000,000	4,310,272	31,553,520	5.0726

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	164	66,871	27.4	97.1	77.3	10,552	Gas	MCF ->	705,607	1,000,000	705,607	4,844,175	7.2440
95														
96	MR SC	149		0.0	0.0		0							
97														
98	TOTAL	20,210	9,563,937	0.0			9,042					86,480,500	381,889,116	3.9930

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Estimated For The Period of : Aug-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	84,901	32.6	95.0	69.5	9,996	Heavy Oil BBLS ->	128,039	6,400,002	819,447	4,122,997	4.8562
2			10,564					Gas MCF ->	134,784	1,000,000	134,784	931,197	8.8145
3													
4	TRKY O 2	394	90,396	36.3	93.7	73.7	9,908	Heavy Oil BBLS ->	135,350	6,400,000	866,239	4,358,403	4.8214
5			16,024					Gas MCF ->	188,199	1,000,000	188,199	1,300,400	8.1151
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,879,100	0.3738
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,914,400	0.3808
10													
11	FT LAUD4	425	291,303	92.1	94.7	97.3	7,620	Gas MCF ->	2,219,610	1,000,000	2,219,610	15,335,844	5.2646
12													
13	FT LAUD5	424	287,557	91.2	93.6	96.2	7,337	Gas MCF ->	2,109,904	1,000,000	2,109,904	14,577,869	5.0696
14													
15	PT EVER1	210	13,483	11.9	95.0	46.8	11,352	Heavy Oil BBLS ->	21,382	6,399,988	136,847	687,047	5.0958
16			5,164					Gas MCF ->	74,839	1,000,000	74,839	517,068	10.0125
17													
18	PT EVER2	210	24,792	19.5	94.4	56.9	10,399	Heavy Oil BBLS ->	37,060	6,399,991	237,186	1,190,702	4.8027
19			5,677					Gas MCF ->	79,660	1,000,000	79,660	550,406	9.6952
20													
21	PT EVER3	381	113,252	44.3	95.1	78.9	9,441	Heavy Oil BBLS ->	162,704	6,400,001	1,041,304	5,227,628	4.6159
22			12,304					Gas MCF ->	144,043	1,000,000	144,043	995,184	8.0882
23													
24	PT EVER4	388	119,904	47.3	95.6	82.6	9,356	Heavy Oil BBLS ->	170,723	6,400,002	1,092,628	5,485,296	4.5747
25			16,674					Gas MCF ->	185,187	1,000,000	185,187	1,279,527	7.6738
26													
27	RIV 3	273	103,341	76.1	93.8	85.0	10,549	Heavy Oil BBLS ->	166,881	6,400,001	1,068,038	5,365,403	5.1919
28			51,293					Gas MCF ->	563,121	1,000,000	563,121	3,890,487	7.5848
29													
30	RIV 4	279	15,058	11.2	92.8	42.0	12,019	Heavy Oil BBLS ->	24,721	6,399,998	158,217	794,867	5.2787
31			8,262					Gas MCF ->	122,064	1,000,000	122,064	841,900	10.1900
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,885,000	0.3097
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,742,000	0.3363
37	CAP CN 1	394	97,394	41.3	94.2	78.4	9,684	Heavy Oil BBLS ->	142,822	6,400,002	914,059	4,579,700	4.7022
38			23,641					Gas MCF ->	257,994	1,000,000	257,994	1,782,562	7.5403
40	CAP CN 2	394	111,094	43.8	94.7	79.9	9,314	Heavy Oil BBLS ->	157,231	6,400,002	1,006,278	5,041,723	4.5383
41			17,324					Gas MCF ->	189,800	1,000,000	189,800	1,311,408	7.5698
43	SANFRD 3	138	16,104	21.2	95.8	61.0	9,887	Heavy Oil BBLS ->	22,655	6,399,992	144,993	675,379	4.1939
44			5,626					Gas MCF ->	69,854	1,000,000	69,854	481,807	8.5647
46	PUTNAM 1	239	118	28.8	95.3	72.0	8,989	Light Oil BBLS ->	173	5,831,116	1,008	7,900	6.7120
47			51,085					Gas MCF ->	459,275	1,000,000	459,275	3,173,433	6.2120
49	PUTNAM 2	239	99	21.1	95.4	63.2	9,627	Light Oil BBLS ->	155	5,828,276	903	7,000	7.1066
50			37,400					Gas MCF ->	360,092	1,000,000	360,092	2,488,097	6.6526
52	MANATE 1	795	267,281	50.3	94.4	63.1	10,158	Heavy Oil BBLS ->	421,638	6,400,000	2,698,484	13,501,967	5.0516
53			30,099					Gas MCF ->	322,307	1,000,000	322,307	2,211,888	7.3487
55	MANATE 2	795	219,031	42.1	95.8	59.8	10,239	Heavy Oil BBLS ->	347,883	6,400,000	2,226,449	11,140,144	5.0861
56			29,986					Gas MCF ->	323,283	1,000,000	323,283	2,218,624	7.3988
58	CUTLER 5	68	4,341	8.6	97.6	37.5	13,008	Gas MCF ->	56,460	1,000,000	56,460	389,700	8.9780
60	CUTLER 6	138	8,940	8.7	96.6	36.9	12,865	Gas MCF ->	115,011	1,000,000	115,011	794,378	8.8858
62	MARTIN 1	803	206,250	55.9	95.9	63.2	10,836	Heavy Oil BBLS ->	342,527	6,400,001	2,192,172	11,009,233	5.3378
63			127,511					Gas MCF ->	1,424,483	1,000,000	1,424,483	9,776,104	7.6669

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Estimated For The Period of : Aug-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	225,171	63.6	96.3	66.0	10,567	Heavy Oil BBLS ->	364,458	6,400,000	2,332,531	11,714,050	5.2023
66			151,245					Gas MCF ->	1,645,071	1,000,000	1,645,071	11,289,942	7.4647
68	MARTIN 3	443	264,664	80.3	95.1	91.2	7,173	Gas MCF ->	1,898,477	1,000,000	1,898,477	13,029,043	4.9229
70	MARTIN 4	443	267,319	81.1	94.6	92.7	7,013	Gas MCF ->	1,874,741	1,000,000	1,874,741	12,866,133	4.8130
72	MARTIN 8	1,080	622,638	77.5	96.6	90.7	6,962	Gas MCF ->	4,334,974	1,000,000	4,334,974	29,821,233	4.7895
74	FM GT	552	31,778	7.7	98.4	52.2	14,704	Light Oil BBLS ->	80,146	5,830,001	467,251	4,354,500	13.7029
76	FL GT	684	170	4.6	91.7	31.9	18,897	Light Oil BBLS ->	525	5,830,160	3,062	20,900	12.2869
77			23,296					Gas MCF ->	440,364	1,000,000	440,364	3,042,564	13.0606
79	PE GT	348	31	8.8	88.3	61.7	18,462	Light Oil BBLS ->	93	5,828,294	540	3,900	12.7036
80			22,422					Gas MCF ->	413,976	1,000,000	413,976	2,860,254	12.7565
82	SJRPP 1O	127	82,923	87.8	93.1	98.5	9,473	Coal TONS ->	32,126	24,451,240	785,508	1,244,600	1.5009
84	SJRPP 2O	127	83,634	88.5	93.6	98.6	9,335	Coal TONS ->	31,929	24,451,183	780,690	1,237,000	1.4791
86	SCHER #4	643	383,088	80.1	94.2	89.1	9,606	Coal TONS ->	210,274	17,500,004	3,679,803	5,861,900	1.5302
88	FMREP 1	1,423	905,082	85.5	94.7	94.5	6,936	Gas MCF ->	6,277,353	1,000,000	6,277,353	43,371,700	4.7920
90	SNREP4	891	557,821	84.1	95.7	94.1	6,943	Gas MCF ->	3,873,163	1,000,000	3,873,163	26,760,586	4.7973
92	SNREP5	940	550,853	78.8	95.2	90.4	6,895	Gas MCF ->	3,798,026	1,000,000	3,798,026	26,241,494	4.7638
94	MANATE 3	1,080	610,432	76.0	96.6	88.5	6,903	Gas MCF ->	4,213,737	1,000,000	4,213,737	30,962,657	5.0723

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Estimated For The Period of : Aug-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	52,410	21.5	97.1	79.1	10,555	Gas MCF ->	553,206	1,000,000	553,206	3,825,806	7.2997
97													
98	MR SC	149		0.0	0.0		0						
99													
100	TOTAL	12,728	5,765,914	0.0			8,167				47,092,117	282,045,401	4.8916

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Estimated For The Period of : Sep-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	77,121	29.7	95.0	75.1	9,929	Heavy Oil BBLS ->	115,338	6,400,000	738,160	3,697,459	4.7943
2			7,101					Gas MCF ->	98,092	1,000,000	98,092	680,749	9.5871
3													
4	TRKY O 2	394	85,998	33.8	93.7	79.1	9,821	Heavy Oil BBLS ->	127,665	6,399,999	817,058	4,092,602	4.7590
5			9,811					Gas MCF ->	123,870	1,000,000	123,870	859,617	8.7622
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,815,100	0.3731
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,849,200	0.3801
10													
11	FT LAUD4	425	280,002	91.5	94.7	96.6	7,613	Gas MCF ->	2,131,626	1,000,000	2,131,626	14,793,006	5.2832
12													
13	FT LAUD5	424	211,775	69.4	71.8	95.5	7,326	Gas MCF ->	1,551,561	1,000,000	1,551,561	10,767,480	5.0844
14													
15	PT EVER1	210	18,575	15.0	95.0	61.3	10,928	Heavy Oil BBLS ->	28,804	6,399,997	184,347	920,966	4.9581
16			4,158					Gas MCF ->	64,076	1,000,000	64,076	444,616	10.6930
17													
18	PT EVER2	210	24,277	19.0	94.4	67.2	10,292	Heavy Oil BBLS ->	35,899	6,399,991	229,751	1,147,860	4.7282
19			4,474					Gas MCF ->	66,147	1,000,000	66,147	459,018	10.2594
20													
21	PT EVER3	381	106,356	43.0	95.1	84.0	9,393	Heavy Oil BBLS ->	151,787	6,399,999	971,439	4,853,304	4.5633
22			11,503					Gas MCF ->	135,577	1,000,000	135,577	940,831	8.1789
23													
24	PT EVER4	388	114,201	46.4	95.6	87.4	9,305	Heavy Oil BBLS ->	161,545	6,399,999	1,033,888	5,165,321	4.5230
25			15,421					Gas MCF ->	172,238	1,000,000	172,238	1,195,235	7.7507
26													
27	RIV 3	273	21,504	13.3	93.8	61.2	11,492	Heavy Oil BBLS ->	35,131	6,399,996	224,839	1,124,082	5.2274
28			4,652					Gas MCF ->	75,753	1,000,000	75,753	524,605	11.2770
29													
30	RIV 4	279	117,391	76.4	92.8	85.3	10,079	Heavy Oil BBLS ->	182,122	6,400,000	1,165,582	5,827,425	4.9641
31			36,124					Gas MCF ->	381,762	1,000,000	381,762	2,649,088	7.3333
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,820,700	0.3091
35	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,682,600	0.3357
37	CAP CN 1	394	97,091	38.7	94.2	82.9	9,594	Heavy Oil BBLS ->	141,389	6,399,998	904,891	4,514,005	4.6492
38			12,559					Gas MCF ->	147,039	1,000,000	147,039	1,020,442	8.1253
40	CAP CN 2	394	106,709	41.8	94.7	84.5	9,265	Heavy Oil BBLS ->	150,209	6,400,002	961,335	4,795,649	4.4942
41			11,838					Gas MCF ->	137,015	1,000,000	137,015	950,911	8.0326
43	SANFRD 3	138	12,114	16.0	95.8	66.7	9,882	Heavy Oil BBLS ->	16,889	6,399,993	108,088	516,811	4.2663
44			3,751					Gas MCF ->	48,687	1,000,000	48,687	337,280	8.9922
46	PUTNAM 1	239	107	20.5	95.3	74.0	8,884	Light Oil BBLS ->	155	5,831,721	905	7,000	6.5482
47			35,250					Gas MCF ->	313,204	1,000,000	313,204	2,173,590	6.1663
49	PUTNAM 2	239	96	14.5	95.4	66.9	9,406	Light Oil BBLS ->	147	5,828,338	856	6,700	7.0157
50			24,909					Gas MCF ->	234,330	1,000,000	234,330	1,626,223	6.5285
52	MANATE 1	795	148,261	28.5	50.4	66.4	10,122	Heavy Oil BBLS ->	233,169	6,399,999	1,492,281	7,441,746	5.0193
53			15,066					Gas MCF ->	160,844	1,000,000	160,844	1,108,779	7.3593
55	MANATE 2	795	274,147	52.9	95.8	66.5	10,158	Heavy Oil BBLS ->	432,386	6,400,000	2,767,270	13,799,876	5.0337
56			28,695					Gas MCF ->	308,983	1,000,000	308,983	2,130,025	7.4229
58	CUTLER 5	68	3,100	6.3	97.6	46.5	12,944	Gas MCF ->	40,130	1,000,000	40,130	278,153	8.9721
60	CUTLER 6	138	6,460	6.5	96.6	45.7	12,648	Gas MCF ->	81,704	1,000,000	81,704	566,692	8.7725
62	MARTIN 1	803	242,752	66.2	95.9	68.6	10,751	Heavy Oil BBLS ->	400,466	6,400,000	2,562,982	12,782,701	5.2658
63			139,806					Gas MCF ->	1,549,882	1,000,000	1,549,882	10,684,701	7.6425

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	240,392	67.8	96.3	70.4	10,516	Heavy Oil BBLS ->	387,614	6,400,001	2,480,733	12,372,473	5.1468
66			148,217					Gas MCF ->	1,606,010	1,000,000	1,606,010	11,071,591	7.4698
68	MARTIN 3	443	251,851	79.0	95.1	91.7	7,152	Gas MCF ->	1,801,289	1,000,000	1,801,289	12,417,846	4.9306
70	MARTIN 4	443	261,304	81.9	94.6	93.5	6,990	Gas MCF ->	1,826,622	1,000,000	1,826,622	12,592,448	4.8191
72	MARTIN 8	1,080	606,458	78.0	96.5	90.5	6,919	Gas MCF ->	4,196,035	1,000,000	4,196,035	28,986,816	4.7800
74	FM GT	552	12,222	3.1	98.4	54.9	14,325	Light Oil BBLS ->	30,030	5,830,003	175,075	1,627,800	13.3192
76	FL GT	684	160	1.7	91.7	33.1	18,620	Light Oil BBLS ->	486	5,829,835	2,833	19,400	12.1554
77			8,288					Gas MCF ->	154,453	1,000,000	154,453	1,071,831	12.9328
79	PE GT	348	24	3.1	88.3	61.8	18,440	Light Oil BBLS ->	71	5,833,098	412	3,000	12.7660
80			7,654					Gas MCF ->	141,170	1,000,000	141,170	979,723	12.7995
82	SJRPP 1O	127	81,583	89.2	93.1	99.2	9,464	Coal TONS ->	31,578	24,450,890	772,115	1,223,800	1.5001
84	SJRPP 2O	127	82,131	89.8	93.6	99.3	9,326	Coal TONS ->	31,326	24,450,824	765,947	1,214,000	1.4781
86	SCHER #4	643	374,847	81.0	94.2	89.7	9,601	Coal TONS ->	205,651	17,500,001	3,598,900	5,733,100	1.5295
88	FMREP 1	1,423	815,572	79.6	94.7	89.8	6,963	Gas MCF ->	5,679,020	1,000,000	5,679,020	39,411,284	4.8323
90	SNREP4	891	533,946	83.2	95.7	94.8	6,920	Gas MCF ->	3,694,670	1,000,000	3,694,670	25,640,215	4.8020
92	SNREP5	940	497,238	73.5	87.3	84.8	6,944	Gas MCF ->	3,453,028	1,000,000	3,453,028	23,968,988	4.8204
94	MANATE 3	1,080	594,173	76.4	96.5	89.0	6,858	Gas MCF ->	4,074,851	1,000,000	4,074,851	30,130,105	5.0709

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	37,461	15.9	97.1	84.8	10,565	Gas MCF ->	395,775	1,000,000	395,775	2,754,195	7.3521
97													
98	MR SC	149		0.0	0.0		0						
99													
100	TOTAL	12,728	5,436,812	0.0			8,096				44,018,199	261,644,210	4.8125

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Estimated For The Period of : Oct-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	81,201	29.4	95.0	78.7	9,862	Heavy Oil BBLS ->	120,692	6,400,000	772,427	3,822,760	4.7078
2			5,032					Gas MCF ->	77,978	1,000,000	77,978	547,627	10.8833
3													
4	TRKY O 2	394	94,573	34.5	93.7	83.2	9,739	Heavy Oil BBLS ->	139,519	6,400,002	892,920	4,419,028	4.6726
5			6,444					Gas MCF ->	90,851	1,000,000	90,851	638,021	9.9005
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,873,200	0.3726
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,907,300	0.3794
10													
11	FT LAUD4	425	288,467	91.2	94.7	96.3	7,597	Gas MCF ->	2,191,436	1,000,000	2,191,436	15,390,134	5.3351
12													
13	FT LAUD5	424		0.0	0.0		0						
14													
15	PT EVER1	210		0.0	0.0		0						
16													
17	PT EVER2	210	21,380	15.5	94.4	78.6	10,068	Heavy Oil BBLS ->	31,108	6,400,009	199,090	982,508	4.5955
18			2,795					Gas MCF ->	44,302	1,000,000	44,302	311,057	11.1295
19													
20	PT EVER3	381	111,255	42.3	95.1	86.3	9,331	Heavy Oil BBLS ->	157,965	6,400,000	1,010,978	4,988,989	4.4843
21			8,732					Gas MCF ->	108,573	1,000,000	108,573	762,445	8.7315
22													
23	PT EVER4	388	121,174	46.3	95.6	89.7	9,253	Heavy Oil BBLS ->	170,628	6,400,002	1,092,020	5,388,937	4.4473
24			12,523					Gas MCF ->	145,069	1,000,000	145,069	1,018,732	8.1346
25													
26	RIV 3	273	122,399	76.1	93.8	85.8	10,414	Heavy Oil BBLS ->	196,318	6,400,001	1,256,436	6,203,339	5.0681
27			32,228					Gas MCF ->	353,860	1,000,000	353,860	2,484,762	7.7099
28													
29	RIV 4	279	7,842	4.6	21.0	80.4	10,798	Heavy Oil BBLS ->	12,125	6,400,013	77,601	383,137	4.8859
30			1,604					Gas MCF ->	24,393	1,000,000	24,393	170,981	10.6603
31													

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Estimated For The Period of : Oct-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	839	39,265	6.3	6.3	100.0	11,025	Nuclear Othr ->	432,899	1,000,000	432,899	121,100	0.3084
34	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,736,200	0.3352
36	CAP CN 1	394	102,967	38.2	94.2	85.8	9,550	Heavy Oil BBLS ->	149,318	6,399,998	955,635	4,709,420	4.5737
37			8,978					Gas MCF ->	113,415	1,000,000	113,415	796,468	8.8715
39	CAP CN 2	394	55,977	20.3	42.7	88.8	9,172	Heavy Oil BBLS ->	78,407	6,400,000	501,804	2,472,933	4.4178
40			3,610					Gas MCF ->	44,707	1,000,000	44,707	314,019	8.6988
42	SANFRD 3	138	12,408	14.7	95.8	76.1	9,628	Heavy Oil BBLS ->	17,041	6,399,995	109,060	530,833	4.2782
43			2,670					Gas MCF ->	36,099	1,000,000	36,099	253,033	9.4787
45	PUTNAM 1	239	29,323	16.5	69.1	70.5	8,735	Gas MCF ->	256,124	1,000,000	256,124	1,798,693	6.1341
47	PUTNAM 2	239	26,594	15.0	95.4	74.1	8,965	Gas MCF ->	238,425	1,000,000	238,425	1,674,389	6.2960
49	MANATE 1	795		0.0	0.0		0						
51	MANATE 2	795	281,519	51.3	95.8	72.4	10,099	Heavy Oil BBLS ->	441,920	6,400,000	2,828,288	13,985,642	4.9679
52			21,779					Gas MCF ->	234,589	1,000,000	234,589	1,637,365	7.5182
54	CUTLER 5	68	3,385	6.7	66.1	72.6	11,769	Gas MCF ->	39,840	1,000,000	39,840	279,473	8.2555
56	CUTLER 6	138	7,606	7.4	65.5	70.5	12,027	Gas MCF ->	91,478	1,000,000	91,478	642,281	8.4442
58	MARTIN 1	803	246,304	63.9	95.9	72.8	10,706	Heavy Oil BBLS ->	404,688	6,400,000	2,590,002	12,706,114	5.1587
59			135,345					Gas MCF ->	1,495,820	1,000,000	1,495,820	10,440,718	7.7141
61	MARTIN 2	796	258,311	68.6	96.3	71.8	10,491	Heavy Oil BBLS ->	415,848	6,400,000	2,661,425	13,056,532	5.0546
62			148,186					Gas MCF ->	1,603,122	1,000,000	1,603,122	11,189,628	7.5511

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MARTIN 3	443	276,568	83.9	95.1	92.4	7,140	Gas MCF ->	1,974,812	1,000,000	1,974,812	13,783,910	4.9839
65													
66	MARTIN 4	443	271,201	82.3	94.6	93.7	6,975	Gas MCF ->	1,891,685	1,000,000	1,891,685	13,203,686	4.8686
67													
68	MARTIN 8	1,080	597,582	74.4	96.6	86.6	6,934	Gas MCF ->	4,143,722	1,000,000	4,143,722	28,955,431	4.8454
69													
70	FM GT	552	5,851	1.4	98.4	92.9	11,467	Light Oil BBLS ->	11,509	5,830,001	67,097	623,900	10.6624
71													
72	FL GT	684	597	0.5	91.7	91.4	14,019	Light Oil BBLS ->	1,385	5,829,975	8,072	55,200	9.2400
73			1,792					Gas MCF ->	25,426	1,000,000	25,426	178,603	9.9661
74													
75	PE GT	348	98	0.2	88.3	93.7	15,348	Light Oil BBLS ->	249	5,830,189	1,452	10,500	10.6925
76			295					Gas MCF ->	4,575	1,000,000	4,575	32,085	10.8947
77													
78	SJRPP 1O	127	83,225	88.1	93.1	99.7	9,461	Coal TONS ->	32,206	24,447,278	787,359	1,250,600	1.5027
79													
80	SJRPP 2O	127	83,858	88.8	93.6	99.7	9,323	Coal TONS ->	31,978	24,447,283	781,785	1,241,700	1.4807
81													
82	SCHER #4	643	383,379	80.2	94.2	90.0	9,599	Coal TONS ->	210,294	17,500,004	3,680,151	5,862,600	1.5292
83													
84	FMREP 1	1,423	898,351	84.9	94.7	94.7	6,922	Gas MCF ->	6,218,799	1,000,000	6,218,799	43,673,667	4.8615
85													
86	SNREP4	891	560,668	84.6	95.7	95.9	6,900	Gas MCF ->	3,868,365	1,000,000	3,868,365	27,166,864	4.8454
87													
88	SNREP5	940	561,150	80.2	95.2	92.6	6,848	Gas MCF ->	3,842,669	1,000,000	3,842,669	26,986,420	4.8091
89													
90	MANATE 3	1,080	628,143	78.2	96.6	89.9	6,834	Gas MCF ->	4,292,536	1,000,000	4,292,536	31,372,807	4.9945
91													
92	FM SC	164	35,868	14.7	97.1	92.3	10,581	Gas MCF ->	379,503	1,000,000	379,503	2,665,159	7.4305
93													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	MR SC	149		0.0	0.0		0						
95													
96	TOTAL	12,967	5,546,977	0.0			7,934				44,007,120	264,473,968	4.7679

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	97,820	39.1	95.0	87.9	8,981	Heavy Oil BBLS ->	132,249	6,399,999	846,396	4,157,381	4.2500
2			13,837					Gas MCF ->	156,399	1,000,000	156,399	1,121,742	8.1071
3													
4	TRKY O 2	397	50,311	22.6	93.7	69.6	9,689	Heavy Oil BBLS ->	70,112	6,400,003	448,718	2,204,009	4.3808
5			14,212					Gas MCF ->	176,425	1,000,000	176,425	1,265,331	8.9034
6													
7	TRKY N 3	717	503,332	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,652,901	1,000,000	5,652,901	1,830,700	0.3637
8													
9	TRKY N 4	717	503,332	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,652,901	1,000,000	5,652,901	1,864,600	0.3705
10													
11	FT LAUD4	443	280,419	87.9	94.7	92.8	7,691	Gas MCF ->	2,156,826	1,000,000	2,156,826	15,469,259	5.5165
12													
13	FT LAUD5	442		0.0	0.0		0						
14													
15	PT EVER1	211	0	0.1	15.8	22.0	20,771	Heavy Oil BBLS ->	0		0	0	
16			89					Gas MCF ->	1,843	1,000,000	1,843	13,228	14.9128
17													
18	PT EVER2	211	7,482	9.5	94.4	54.9	10,932	Heavy Oil BBLS ->	9,261	6,400,002	59,269	291,141	3.8913
19			6,898					Gas MCF ->	97,921	1,000,000	97,921	702,291	10.1818
20													
21	PT EVER3	383	71,045	29.4	95.1	77.4	10,285	Heavy Oil BBLS ->	109,047	6,400,001	697,900	3,428,524	4.8259
22			10,058					Gas MCF ->	136,217	1,000,000	136,217	976,916	9.7127
23													
24	PT EVER4	390	31,949	15.7	95.6	56.9	11,839	Heavy Oil BBLS ->	53,285	6,399,997	341,025	1,675,263	5.2435
25			12,142					Gas MCF ->	180,969	1,000,000	180,969	1,297,944	10.6895
26													
27	RIV 3	275	6,335	6.5	93.8	45.8	13,087	Heavy Oil BBLS ->	8,844	6,399,991	56,603	277,308	4.3775
28			6,573					Gas MCF ->	112,324	1,000,000	112,324	803,312	12.2221
29													
30	RIV 4	281	80,707	51.6	74.2	79.8	9,163	Heavy Oil BBLS ->	113,634	6,400,001	727,256	3,562,491	4.4141
31			23,639					Gas MCF ->	228,813	1,000,000	228,813	1,640,903	6.9416
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853		0.0	0.0		0						
35	ST LUC 2	726	509,586	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,525,890	1,000,000	5,525,890	1,677,100	0.3291
37	CAP CN 1	398	86,460	34.8	94.2	83.8	9,649	Heavy Oil BBLS ->	125,767	6,399,998	804,906	3,936,662	4.5531
38			13,296					Gas MCF ->	157,685	1,000,000	157,685	1,130,978	8.5060
40	CAP CN 2	398	4,628	2.1	15.8	74.4	10,103	Heavy Oil BBLS ->	6,799	6,400,026	43,513	212,844	4.5994
41			1,470					Gas MCF ->	18,084	1,000,000	18,084	129,673	8.8243
43	SANFRD 3	140	2,748	6.2	95.8	47.3	12,063	Heavy Oil BBLS ->	3,754	6,400,059	24,024	117,500	4.2765
44			3,524					Gas MCF ->	51,633	1,000,000	51,633	369,506	10.4848
46	PUTNAM 1	250	22,685	12.6	66.7	67.1	9,028	Gas MCF ->	204,799	1,000,000	204,799	1,468,893	6.4752
48	PUTNAM 2	250	18,947	10.5	95.4	67.0	9,262	Gas MCF ->	175,480	1,000,000	175,480	1,258,596	6.6428
50	MANATE 1	821		0.0	0.0		0						
52	MANATE 2	821	130,765	25.9	95.8	60.5	10,737	Heavy Oil BBLS ->	216,719	6,400,000	1,387,001	6,846,339	5.2356
53			22,509					Gas MCF ->	258,771	1,000,000	258,771	1,844,465	8.1942
55	CUTLER 5	70	317	0.6	32.5	37.4	14,766	Gas MCF ->	4,680	1,000,000	4,680	33,434	10.5470
57	CUTLER 6	142		0.0	0.0		0						
59	MARTIN 1	813	132,089	36.6	95.9	67.4	11,322	Heavy Oil BBLS ->	228,732	6,400,001	1,463,887	7,125,300	5.3943
60			82,128					Gas MCF ->	961,453	1,000,000	961,453	6,852,822	8.3441
62	MARTIN 2	804	69,398	19.7	96.3	56.7	11,631	Heavy Oil BBLS ->	122,946	6,400,002	786,854	3,829,937	5.5188
63			44,676					Gas MCF ->	539,884	1,000,000	539,884	3,848,063	8.6133

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 3	465	257,333	76.9	95.1	88.0	7,122	Gas	MCF ->	1,832,779	1,000,000	1,832,779	13,063,338	5.0764
67	MARTIN 4	466	267,314	79.7	94.6	89.5	6,879	Gas	MCF ->	1,838,750	1,000,000	1,838,750	13,105,812	4.9028
69	MARTIN 8	1,099	565,339	71.4	96.5	83.9	6,630	Gas	MCF ->	3,748,032	1,000,000	3,748,032	26,717,823	4.7260
71	FM GT	624	927	0.2	98.4	92.3	12,165	Light Oil	BBLS ->	1,935	5,830,034	11,278	104,900	11.3149
73	FL GT	768	68	0.0	91.7	89.6	13,996	Light Oil	BBLS ->	158	5,828,590	922	6,300	9.2240
74			205					Gas	MCF ->	2,903	1,000,000	2,903	20,864	10.1825
76	PE GT	384	6	0.0	88.3	92.0	14,388	Light Oil	BBLS ->	14	5,841,727	81	600	10.1695
77			18					Gas	MCF ->	256	1,000,000	256	1,826	10.3747
79	SJRPP 1O	130	82,353	88.0	93.1	99.6	9,638	Coal	TONS ->	32,468	24,446,915	793,740	1,262,000	1.5324
81	SJRPP 2O	130	82,893	88.6	93.6	99.7	9,499	Coal	TONS ->	32,208	24,446,956	787,385	1,251,900	1.5103
83	SCHER #4	648	371,448	79.6	94.2	89.7	9,825	Coal	TONS ->	208,548	17,499,997	3,649,596	5,813,900	1.5652
85	FMREP 1	1,451	859,088	82.2	94.7	91.1	6,871	Gas	MCF ->	5,903,126	1,000,000	5,903,126	42,338,451	4.9283
87	SNREP4	938	530,986	78.6	95.7	92.2	6,841	Gas	MCF ->	3,632,691	1,000,000	3,632,691	26,054,445	4.9068
89	SNREP5	938	521,403	77.2	95.2	89.1	6,776	Gas	MCF ->	3,533,084	1,000,000	3,533,084	25,340,065	4.8600
91	MANATE 3	1,105	587,122	73.8	96.5	87.3	6,699	Gas	MCF ->	3,932,936	1,000,000	3,932,936	28,917,142	4.9252
93	FM SC	166	36,376	15.2	97.1	89.6	10,926	Gas	MCF ->	397,459	1,000,000	397,459	2,850,663	7.8366

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	MR SC	163		0.0	0.0		0						
96													
97	TOTAL	13,446	4,686,392	0.0			7,649				35,847,824	219,957,877	4.6935

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Estimated For The Period of : Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	40,809	17.1	95.0	69.6	9,644	Heavy Oil BBLS ->	56,333	6,400,001	360,533	1,762,798	4.3196
2			9,829					Gas MCF ->	127,803	1,000,000	127,803	940,298	9.5670
3													
4	TRKY O 2	397	14,534	8.2	93.7	47.5	11,166	Heavy Oil BBLS ->	21,132	6,399,995	135,245	661,276	4.5499
5			9,602					Gas MCF ->	134,266	1,000,000	134,266	987,937	10.2888
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,888,100	0.3630
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,923,200	0.3698
10													
11	FT LAUD4	443	281,031	85.3	94.7	90.0	7,833	Gas MCF ->	2,201,389	1,000,000	2,201,389	16,196,587	5.7633
12													
13	FT LAUD5	442	193,842	58.9	81.5	80.4	8,154	Gas MCF ->	1,580,633	1,000,000	1,580,633	11,629,412	5.9994
14													
15	PT EVER1	211	903	3.0	95.0	33.3	15,771	Heavy Oil BBLS ->	1,270	6,399,858	8,129	40,057	4.4360
16			3,809					Gas MCF ->	66,175	1,000,000	66,175	486,868	12.7837
17													
18	PT EVER2	211	1,749	3.7	94.4	38.4	13,753	Heavy Oil BBLS ->	2,256	6,400,027	14,436	71,156	4.0686
19			4,042					Gas MCF ->	65,207	1,000,000	65,207	479,709	11.8684
20													
21	PT EVER3	383	21,218	10.9	95.1	54.2	11,704	Heavy Oil BBLS ->	34,210	6,400,001	218,947	1,079,822	5.0892
22			9,792					Gas MCF ->	143,974	1,000,000	143,974	1,059,259	10.8181
23													
24	PT EVER4	390	8,038	5.2	95.6	35.0	14,371	Heavy Oil BBLS ->	14,571	6,400,015	93,256	459,948	5.7219
25			6,982					Gas MCF ->	122,610	1,000,000	122,610	902,086	12.9196
26													
27	RIV 3	275	121,180	69.2	93.8	77.4	8,534	Heavy Oil BBLS ->	159,741	6,400,001	1,022,343	4,949,020	4.0840
28			20,328					Gas MCF ->	185,270	1,000,000	185,270	1,362,932	6.7047
29													
30	RIV 4	281	1,003	2.3	92.8	27.9	18,703	Heavy Oil BBLS ->	1,600	6,400,000	10,240	49,524	4.9361
31			3,770					Gas MCF ->	79,045	1,000,000	79,045	579,798	15.3776
32													

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Estimated For The Period of : Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	598,803	94.4	94.4	100.0	10,844	Nuclear Othr ->	6,493,443	1,000,000	6,493,443	2,094,200	0.3497
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,729,600	0.3285
37	CAP CN 1	398	38,180	18.3	94.2	73.1	10,188	Heavy Oil BBLS ->	56,111	6,399,996	359,108	1,739,853	4.5570
38			16,025					Gas MCF ->	193,132	1,000,000	193,132	1,421,014	8.8673
40	CAP CN 2	398	58,664	25.1	94.7	79.1	9,853	Heavy Oil BBLS ->	85,772	6,400,003	548,940	2,659,654	4.5337
41			15,617					Gas MCF ->	182,943	1,000,000	182,943	1,346,066	8.6192
43	SANFRD 3	140	464	2.8	95.8	32.1	15,427	Heavy Oil BBLS ->	683	6,399,620	4,374	21,438	4.6193
44			2,416					Gas MCF ->	40,054	1,000,000	40,054	293,870	12.1650
46	PUTNAM 1	250	11,093	6.0	95.3	58.1	9,417	Gas MCF ->	104,461	1,000,000	104,461	768,568	6.9286
48	PUTNAM 2	250	7,927	4.3	95.4	53.9	9,838	Gas MCF ->	77,982	1,000,000	77,982	573,753	7.2381
50	MANATE 1	821	75,267	14.0	94.4	58.9	10,638	Heavy Oil BBLS ->	123,031	6,400,000	787,398	3,859,093	5.1272
51			10,395					Gas MCF ->	123,879	1,000,000	123,879	905,713	8.7131
53	MANATE 2	821	70,585	16.7	95.8	40.6	11,259	Heavy Oil BBLS ->	121,086	6,400,000	774,949	3,797,999	5.3808
54			31,543					Gas MCF ->	374,943	1,000,000	374,943	2,741,175	8.6902
56	CUTLER 5	70	1,049	2.0	97.6	30.0	16,893	Gas MCF ->	17,714	1,000,000	17,714	129,831	12.3813
58	CUTLER 6	142	1,870	1.8	90.4	30.2	12,935	Gas MCF ->	24,192	1,000,000	24,192	177,784	9.5052
60	MARTIN 1	813	70,319	21.7	95.9	49.5	11,853	Heavy Oil BBLS ->	126,569	6,400,002	810,039	3,923,208	5.5792
61			60,879					Gas MCF ->	744,991	1,000,000	744,991	5,446,604	8.9466

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Estimated For The Period of : Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	804	31,178	9.9	96.3	41.9	12,087	Heavy Oil BBLS ->	56,768	6,399,996	363,314	1,759,586	5.6436
64			28,340					Gas MCF ->	356,090	1,000,000	356,090	2,603,332	9.1862
66	MARTIN 3	465	221,233	63.9	95.1	85.1	7,167	Gas MCF ->	1,585,593	1,000,000	1,585,593	11,592,117	5.2398
68	MARTIN 4	466	240,959	69.5	94.6	85.4	6,935	Gas MCF ->	1,670,963	1,000,000	1,670,963	12,216,231	5.0698
70	MARTIN 8	1,099	533,795	65.3	96.6	76.2	6,780	Gas MCF ->	3,619,211	1,000,000	3,619,211	26,460,711	4.9571
72	FM GT	624	458	0.1	98.4	47.8	15,960	Light Oil BBLS ->	1,255	5,830,079	7,315	68,000	14.8374
74	FL GT	768	0	0.0	91.7		13,917	Light Oil BBLS ->	1	6,111,111	6	0	0.0000
75			1					Gas MCF ->	17	1,000,000	17	115	9.6210
77	PE GT	384	0	0.0	88.3		0	Light Oil BBLS ->	0		0	0	
78			0					Gas MCF ->	0	1,000,000	0	0	
80	SJRPP 1O	130	85,736	88.6	93.1	99.5	9,638	Coal TONS ->	33,801	24,446,534	826,322	1,314,300	1.5330
82	SJRPP 2O	130	86,351	89.3	93.6	99.6	9,499	Coal TONS ->	33,551	24,446,552	820,209	1,304,600	1.5108
84	SCHER #4	648	387,095	80.3	94.2	89.7	9,825	Coal TONS ->	217,325	17,500,001	3,803,191	6,058,600	1.5651
86	FMREP 1	1,451	824,412	76.4	94.7	85.8	6,923	Gas MCF ->	5,707,459	1,000,000	5,707,459	41,992,220	5.0936
88	SNREP4	938	502,208	72.0	95.7	86.5	6,938	Gas MCF ->	3,484,461	1,000,000	3,484,461	25,636,644	5.1048
90	SNREP5	938	481,117	68.9	95.2	80.2	6,946	Gas MCF ->	3,341,621	1,000,000	3,341,621	24,585,692	5.1101
92	MANATE 3	1,105	519,071	63.1	96.6	76.5	6,904	Gas MCF ->	3,583,525	1,000,000	3,583,525	26,613,919	5.1272

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Estimated For The Period of : Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	166	25,734	10.4	97.1	83.0	10,926	Gas MCF ->	281,173	1,000,000	281,173	2,068,701	8.0389
95													
96	MR SC	163		8.4	0.0	98.6	8,766	Gas MCF ->	9	1,000,000	9	402,443	6.6742
97													
98	TOTAL	13,446	4,308,614	0.0	0.0		0						

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	395	944,691	31.2	95.0	78.3	9,563	Heavy Oil BBLS ->	1,356,408	6,400,000	8,681,008	43,569,308	4.6120
2			133,990					Gas MCF ->	1,634,697	1,000,000	1,634,697	11,903,551	8.8839
3													
4	TRKY O 2	395	637,015	21.8	74.4	74.0	9,861	Heavy Oil BBLS ->	934,846	6,400,000	5,983,013	29,981,533	4.7066
5			118,720					Gas MCF ->	1,468,968	1,000,000	1,468,968	10,521,345	8.8623
6			0						0		0	0	0.0000
7													
8	TRKY N 3	703	6,003,740	97.5	97.5	100.0	11,378	Nuclear Othr ->	68,308,914	1,000,000	68,308,914	22,258,300	0.3707
9													
10	TRKY N 4	703	4,949,673	80.4	80.1	100.0	11,355	Nuclear Othr ->	56,203,111	1,000,000	56,203,111	17,484,200	0.3532
11													
12													
13	FT LAUD4	433	3,278,217	86.5	91.6	94.7	7,654	Gas MCF ->	25,091,063	1,000,000	25,091,063	180,354,760	5.5016
14													
15	FT LAUD5	432	2,622,653	69.4	75.2	92.2	7,548	Gas MCF ->	19,794,804	1,000,000	19,794,804	143,207,078	5.4604
16			0						0		0	0	0.0000
17													
18	PT EVER1	210	114,261	8.8	80.5	55.1	11,216	Heavy Oil BBLS ->	171,361	6,400,004	1,096,709	5,500,939	4.8143
19			47,754					Gas MCF ->	720,505	1,000,000	720,505	5,254,692	11.0037
20													
21													
22	PT EVER2	210	141,704	10.2	73.2	59.6	10,573	Heavy Oil BBLS ->	203,462	6,400,000	1,302,158	6,515,866	4.5982
23			46,690					Gas MCF ->	689,644	1,000,000	689,644	4,965,291	10.6345
24			0						0		0	0	0.0000
25													
26	PT EVER3	382	944,161	32.2	89.6	79.1	9,693	Heavy Oil BBLS ->	1,372,024	6,400,001	8,780,957	43,835,161	4.6428
27			132,410					Gas MCF ->	1,654,313	1,000,000	1,654,313	11,871,800	8.9659
28													
29	PT EVER4	389	958,311	33.0	95.6	79.0	9,755	Heavy Oil BBLS ->	1,390,025	6,400,000	8,896,159	44,467,496	4.6402
30			166,854					Gas MCF ->	2,080,294	1,000,000	2,080,294	14,958,709	8.9651
31													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIV 3	274	746,428	39.3	86.6	77.5	10,055	Heavy Oil BBLS ->	1,126,086	6,400,000	7,206,949	35,944,867	4.8156
33			196,387					Gas MCF ->	2,273,038	1,000,000	2,273,038	16,102,041	8.1992
34													
35	RIV 4	280	733,841	38.9	85.2	79.1	9,876	Heavy Oil BBLS ->	1,089,721	6,400,000	6,974,211	35,022,020	4.7724
36			219,637					Gas MCF ->	2,442,113	1,000,000	2,442,113	17,392,099	7.9186
37													
38	ST LUC 1	845	6,027,256	81.4	81.5	100.0	10,953	Nuclear Othr ->	66,016,701	1,000,000	66,016,701	18,908,000	0.3137
39													
40													
41	ST LUC 2	719	6,140,275	97.5	97.5	100.0	10,949	Nuclear Othr ->	67,232,131	1,000,000	67,232,131	20,538,000	0.3345
42													
43	CAP CN 1	396	816,954	28.2	79.7	80.6	9,707	Heavy Oil BBLS ->	1,192,249	6,399,999	7,630,392	37,959,749	4.6465
44			161,346					Gas MCF ->	1,865,797	1,000,000	1,865,797	13,284,562	8.2336
45													
46													
47	CAP CN 2	396	971,820	32.7	83.8	82.6	9,439	Heavy Oil BBLS ->	1,383,086	6,400,001	8,851,752	44,282,144	4.5566
48			160,031					Gas MCF ->	1,832,302	1,000,000	1,832,302	13,274,736	8.2951
49													
50	SANFRD 3	139	102,095	11.8	90.3	61.2	10,260	Heavy Oil BBLS ->	142,006	6,399,993	908,836	4,155,953	4.0707
51			41,131					Gas MCF ->	560,619	1,000,000	560,619	4,015,473	9.7627
52													
53	PUTNAM 1	244	373,604	17.5	86.1	70.0	8,954	Gas MCF ->	3,345,480	1,000,000	3,345,480	23,785,425	6.3665
54			482					Light Oil BBLS ->	692	5,830,202	4,035	31,500	6.5353
55													
56	PUTNAM 2	244	298,778	14.0	88.9	66.6	9,350	Gas MCF ->	2,793,707	1,000,000	2,793,707	19,938,824	6.6735
57			400					Light Oil BBLS ->	607	5,829,216	3,540	27,600	6.9086
58													
59	MANATE 1	806	2,160,386	33.5	75.0	65.2	10,128	Heavy Oil BBLS ->	3,395,987	6,400,000	21,734,317	108,723,264	5.0326
60			206,222					Gas MCF ->	2,234,592	1,000,000	2,234,592	16,253,190	7.8814
61			0						0		0	0	0.0000
62													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATE 2	806	2,327,296	37.2	95.8	61.9	10,324	Heavy Oil BBLS ->	3,715,818	6,400,000	23,781,237	118,574,513	5.0949
64			298,644					Gas MCF ->	3,330,129	1,000,000	3,330,129	24,232,837	8.1143
65													
66	CUTLER 5	69	33,836	5.6	89.6	45.3	12,667	Gas MCF ->	428,586	1,000,000	428,586	3,054,599	9.0277
67													
68	CUTLER 6	140	69,916	5.7	85.5	44.5	12,299	Gas MCF ->	859,865	1,000,000	859,865	6,105,760	8.7331
69													
70													
71	MARTIN 1	807	1,835,330	41.5	79.4	65.7	10,881	Heavy Oil BBLS ->	3,055,609	6,400,001	19,555,899	97,198,150	5.2959
72			1,099,661					Gas MCF ->	12,379,303	1,000,000	12,379,303	86,593,195	7.8745
73			0						0		0	0	0.0000
74													
75	MARTIN 2	799	2,178,526	50.4	96.3	67.5	10,581	Heavy Oil BBLS ->	3,528,573	6,400,000	22,582,866	112,830,534	5.1792
76			1,351,815					Gas MCF ->	14,773,350	1,000,000	14,773,350	104,648,517	7.7413
77													
78	MARTIN 3	452	3,092,943	78.1	94.3	89.1	7,149	Gas MCF ->	22,111,331	1,000,000	22,111,331	158,573,525	5.1269
79													
80	MARTIN 4	453	3,112,541	78.5	92.2	89.8	6,961	Gas MCF ->	21,667,249	1,000,000	21,667,249	155,280,177	4.9889
81													
82	MARTIN 8	1,088	4,178,436	43.8	98.0	86.7	6,877	Gas MCF ->	28,734,764	1,000,000	28,734,764	200,599,719	4.8001
83													
84	FM GT	582	128,859	2.5	96.4	52.1	14,609	Light Oil BBLS ->	322,897	5,830,001	1,882,488	17,754,000	13.7778
85													
86	FL GT	719	1,713	1.4	91.7	31.7	18,639	Light Oil BBLS ->	4,493	5,830,017	26,197	179,200	10.4593
87			88,294					Gas MCF ->	1,651,435	1,000,000	1,651,435	11,630,826	13.1728
88													
89	PE GT	363	411	2.6	88.3	58.9	18,311	Light Oil BBLS ->	1,144	5,831,307	6,668	48,200	11.7332
90			81,838					Gas MCF ->	1,499,387	1,000,000	1,499,387	10,552,551	12.8945
91													
92	SJRPP 1O	128	824,409	73.4	78.1	99.2	9,534	Coal TONS ->	321,432	24,452,470	7,859,801	12,480,800	1.5139
93													
94													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	SJRPP 2O	128	1,001,597	89.2	93.6	99.4	9,399	Coal TONS ->	384,968	24,453,397	9,413,770	14,939,400	1.4916
97	SCHER #4	645	4,536,350	80.3	94.2	89.7	9,694	Coal TONS ->	2,512,876	17,500,002	43,975,336	69,980,300	1.5427
99	FMREP 1	1,435	10,267,693	81.7	93.2	91.4	6,918	Gas MCF ->	71,030,742	1,000,000	71,030,742	510,893,211	4.9757
101	SNREP4	911	6,445,312	80.8	95.2	92.5	6,914	Gas MCF ->	44,561,358	1,000,000	44,561,358	320,980,717	4.9801
103	SNREP5	939	6,257,420	76.1	92.6	87.7	6,875	Gas MCF ->	43,021,216	1,000,000	43,021,216	310,015,412	4.9544
105	MANATE 3	1,090	4,158,969	43.6	98.0	86.8	6,849	Gas MCF ->	28,486,240	1,000,000	28,486,240	209,569,990	5.0390
107	FM SC	165	424,142	29.7	95.5	100.0	10,695	Gas MCF ->	4,539,180	1,000,000	4,539,180	32,686,225	7.7064
108			4,591					Light Oil BBLS ->	7,933	5,829,987	46,249	443,200	9.6537
110	MR SC	155	0	0.0	0.0	0.0	0		0		0	0	0.0000
112	TOTAL	20,466	94,398,455				8,946				844,501,469	3,616,135,032	3.8307

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2005 thru June 2005

			January 2005	February 2005	March 2005	April 2005	May 2005	June 2005
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	902,834	1,139,451	1,744,609	2,274,241	3,406,900	2,705,906
3	Unit Cost	($/BBLS)	32.9684	32.3638	31.6472	31.4338	31.8237	32.1264
4	Amount	($)	29,765,000	36,877,000	55,212,000	71,488,000	108,420,000	86,931,000
5								
6	Burned:							
7	Units	(BBLS)	1,006,963	1,144,807	1,595,357	2,183,270	3,333,847	2,619,546
8	Unit Cost	($/BBLS)	32.8590	32.7204	32.3299	31.8783	31.8169	31.9394
9	Amount	($)	33,087,835	37,458,500	51,577,745	69,599,003	106,072,579	83,666,800
10								
11	Ending Inventory:							
12	Units	(BBLS)	2,654,374	2,649,019	2,798,270	2,889,242	2,962,292	3,048,656
13	Unit Cost	($/BBLS)	32.8081	32.8066	32.1520	31.7834	31.7623	31.8900
14	Amount	($)	87,084,957	86,375,410	89,969,945	91,829,814	94,089,135	97,221,672
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	31,377	14,249	41	54,662	35,992	3,143
21	Unit Cost	($/BBLS)	57.9087	57.8286	48.7805	55.4864	53.9009	52.8158
22	Amount	($)	1,817,000	824,000	2,000	3,033,000	1,940,000	166,000
23								
24	Burned:							
25	Units	(BBLS)	39,562	14,249	4,215	885	36,680	3,500
26	Unit Cost	($/BBLS)	56.0356	56.3794	55.0225	54.6102	55.3476	53.9771
27	Amount	($)	2,216,880	803,350	231,920	48,330	2,030,150	188,920
28								
29	Ending Inventory:							
30	Units	(BBLS)	527,123	527,121	522,947	576,724	576,037	575,680
31	Unit Cost	($/BBLS)	45.8728	45.9121	45.8385	46.7394	46.6396	46.6298
32	Amount	($)	24,180,607	24,201,214	23,971,090	26,955,739	26,866,135	26,843,821
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	66,179	58,618	33,837	32,238	64,740	67,775
39	Unit Cost	($/Tons)	38.5168	38.6035	38.5081	38.6500	38.6314	38.6278
40	Amount	($)	2,549,000	2,257,000	1,303,000	1,246,000	2,501,000	2,618,000
41								
42	Burned:							
43	Units	(Tons)	66,179	58,618	33,837	32,238	64,740	63,253
44	Unit Cost	($/Tons)	39.3267	38.8638	38.7088	38.6772	38.6535	38.6407
45	Amount	($)	2,602,599	2,278,117	1,309,788	1,246,875	2,502,429	2,444,138
46								
47	Ending Inventory:							
48	Units	(Tons)	45,217	45,217	45,217	45,217	45,218	49,740
49	Unit Cost	($/Tons)	39.5794	39.1173	38.9630	38.9374	38.9130	38.8770
50	Amount	($)	1,789,663	1,768,768	1,761,788	1,760,632	1,759,587	1,933,740
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	3,732,610	3,418,870	3,836,333	3,597,615	3,701,933	3,884,905
57	Unit Cost	($/MBTU)	1.5930	1.5929	1.5929	1.5930	1.5930	1.5931
58	Amount	($)	5,946,000	5,446,000	6,111,000	5,731,000	5,897,000	6,205,000
59								
60	Burned:							
61	Units	(MBTU)	3,732,610	3,418,870	3,836,333	3,597,615	3,701,933	3,604,353
62	Unit Cost	($/MBTU)	1.5819	1.5879	1.5908	1.5920	1.5926	1.5929
63	Amount	($)	5,904,641	5,428,886	6,102,949	5,727,571	5,895,705	5,741,201
64								
65	Ending Inventory:							
66	Units	(MBTU)	2,905,560	2,905,560	2,905,560	2,905,525	2,905,525	3,196,078
67	Unit Cost	($/MBTU)	1.5819	1.5879	1.5908	1.5921	1.5926	1.5929
68	Amount	($)	4,596,301	4,613,779	4,622,231	4,625,772	4,627,375	5,090,902
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
75	Unit Cost	($/MCF)	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
76	Amount	($)	198,076,044	177,057,456	182,480,002	181,854,572	200,527,134	242,086,322
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,049
83	Unit Cost	($/MBTU)	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
84	Amount	($)	7,174,687	6,468,144	7,147,577	5,759,496	5,525,202	6,449,491

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2005 thru December 2005

			July 2005	August 2005	September 2005	October 2005	November 2005	December 2005	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	2,610,470	2,646,073	2,450,414	2,335,576	1,001,149	808,825	24,026,448
3	Unit Cost	($/BBLS)	32.2329	32.2240	31.7799	31.0086	30.6068	29.9546	31.7679
4	Amount	($)	84,143,000	85,267,000	77,874,000	72,423,000	30,642,000	24,228,000	763,270,000
5									
6	Burned:								
7	Units	(BBLS)	2,529,125	2,646,073	2,600,414	2,335,576	1,201,149	861,132	24,057,259
8	Unit Cost	($/BBLS)	32.0280	32.0832	31.9381	31.5339	31.3572	31.1618	31.9472
9	Amount	($)	81,002,720	84,894,368	83,052,400	73,649,915	37,664,690	26,834,391	768,560,945
10									
11	Ending Inventory:								
12	Units	(BBLS)	3,129,999	3,130,000	2,979,999	2,980,000	2,780,000	2,727,693	2,727,693
13	Unit Cost	($/BBLS)	32.0175	32.0912	31.9438	31.5473	31.3251	31.0340	31.0340
14	Amount	($)	100,214,601	100,445,520	95,192,516	94,011,047	87,083,662	84,651,330	84,651,330
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	109,908	80,567	30,403	249	14	0	360,605
21	Unit Cost	($/BBLS)	52.9989	53.0366	53.1855	40.1606	71.4286	0.0000	54.0980
22	Amount	($)	5,825,000	4,273,000	1,617,000	10,000	1,000	0	19,508,000
23									
24	Burned:								
25	Units	(BBLS)	110,188	81,092	30,889	13,143	2,107	1,255	337,765
26	Unit Cost	($/BBLS)	54.7840	54.1888	53.8664	52.4637	53.0375	54.1912	54.7231
27	Amount	($)	6,036,540	4,394,280	1,663,880	689,530	111,750	68,010	18,483,540
28									
29	Ending Inventory:								
30	Units	(BBLS)	575,400	574,875	574,389	561,495	559,403	558,147	558,147
31	Unit Cost	($/BBLS)	46.2846	46.1153	46.0738	45.9219	45.8949	45.8762	45.8762
32	Amount	($)	26,632,187	26,510,551	26,464,302	25,784,900	25,673,722	25,605,670	25,605,670
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	64,366	64,055	62,905	59,664	64,676	67,352	706,405
39	Unit Cost	($/Tons)	38.7782	38.7636	38.7589	38.9012	38.9016	38.8853	38.7129
40	Amount	($)	2,496,000	2,483,000	2,438,000	2,321,000	2,516,000	2,619,000	27,347,000
41									
42	Burned:								
43	Units	(Tons)	64,366	64,055	62,905	64,186	64,676	67,352	706,405
44	Unit Cost	($/Tons)	38.7119	38.7424	38.7531	38.8310	38.8689	38.8823	38.8185
45	Amount	($)	2,491,730	2,481,644	2,437,766	2,492,407	2,513,888	2,618,801	27,420,182
46									
47	Ending Inventory:								
48	Units	(Tons)	49,740	49,740	49,740	45,218	45,217	45,217	45,217
49	Unit Cost	($/Tons)	38.9540	38.9851	38.9963	39.1050	39.1445	39.1582	39.1582
50	Amount	($)	1,937,571	1,939,121	1,939,678	1,768,251	1,769,999	1,770,617	1,770,617
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	3,671,990	3,679,795	3,598,893	3,389,593	3,649,590	3,803,188	43,975,313
57	Unit Cost	($/MBTU)	1.5931	1.5930	1.5930	1.5931	1.5931	1.5931	1.5930
58	Amount	($)	5,850,000	5,862,000	5,733,000	5,400,000	5,814,000	6,059,000	70,054,000
59									
60	Burned:								
61	Units	(MBTU)	3,671,990	3,679,795	3,598,893	3,660,145	3,649,590	3,803,188	43,975,313
62	Unit Cost	($/MBTU)	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930	1.5914
63	Amount	($)	5,849,304	5,861,906	5,733,104	5,862,574	5,813,918	6,058,608	69,980,367
64									
65	Ending Inventory:								
66	Units	(MBTU)	3,196,078	3,196,078	3,196,078	2,905,525	2,905,560	2,905,560	2,905,560
67	Unit Cost	($/MBTU)	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930
68	Amount	($)	5,091,218	5,091,365	5,091,433	4,628,607	4,628,622	4,628,629	4,628,629
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
75	Unit Cost	($/MCF)	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
76	Amount	($)	279,078,237	268,919,464	243,216,162	238,368,779	218,637,616	222,198,659	2,652,500,447
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,967,112	23,967,112	23,193,979	17,690,116	16,831,692	23,886,181	257,760,861
83	Unit Cost	($/MBTU)	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
84	Amount	($)	7,430,320	7,420,550	7,167,595	5,637,812	5,372,358	7,635,077	79,188,309

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POWER SOLD

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	275,000		275,000	4.608	5.136	12,671,000	14,125,000	750,000
2005	St.Lucie Rel.		46,084		46,084	0.309	0.309	142,229	142,229	0
Total			321,084	0	321,084	3.991	4.443	12,813,229	14,267,229	750,000
February		OS	260,000		260,000	4.468	5.069	11,617,350	13,180,000	885,800
2005	St.Lucie Rel.		41,624		41,624	0.308	0.308	128,223	128,223	0
Total			301,624	0	301,624	3.894	4.412	11,745,573	13,308,223	885,800
March		OS	225,000		225,000	4.622	5.244	10,399,000	11,800,000	787,500
2005	St.Lucie Rel.		46,084		46,084	0.307	0.307	141,691	141,691	0
Total			271,084	0	271,084	3.888	4.405	10,540,691	11,941,691	787,500
April		OS	175,000		175,000	4.718	5.414	8,256,500	9,475,000	736,750
2005	St.Lucie Rel.		43,865		43,865	0.312	0.312	136,887	136,887	0
Total			218,865	0	218,865	3.835	4.392	8,393,387	9,611,887	736,750
May		OS	150,000		150,000	4.928	5.667	7,391,500	8,500,000	672,000
2005	St.Lucie Rel.		45,328		45,328	0.311	0.311	141,181	141,181	0
Total			195,328	0	195,328	3.856	4.424	7,532,681	8,641,181	672,000
June		OS	200,000		200,000	5.059	5.975	10,117,400	11,950,000	1,190,100
2005	St.Lucie Rel.		43,865		43,865	0.311	0.311	136,375	136,375	0
Total			243,865	0	243,865	4.205	4.956	10,253,775	12,086,375	1,190,100

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POWER SOLD

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	190,000		190,000	4.893	5.947	9,296,300	11,300,000	1,395,800
2005	St.Lucie Rel.		45,328		45,328	0.310	0.310	140,653	140,653	0
Total			235,328	0	235,328	4.010	4.862	9,436,953	11,440,653	1,395,800
August		OS	190,000		190,000	4.963	6.032	9,429,800	11,460,000	1,422,300
2005	St.Lucie Rel.		45,328		45,328	0.310	0.310	140,393	140,393	0
Total			235,328	0	235,328	4.067	4.929	9,570,193	11,600,393	1,422,300
September		OS	180,000		180,000	5.045	5.683	9,080,400	10,230,000	576,300
2005	St.Lucie Rel.		43,865		43,865	0.309	0.309	135,604	135,604	0
Total			223,865	0	223,865	4.117	4.630	9,216,004	10,365,604	576,300
October		OS	160,000		160,000	4.936	5.497	7,896,800	8,795,000	427,100
2005	St.Lucie Rel.		2,924		2,924	0.309	0.309	9,023	9,023	0
Total			162,924	0	162,924	4.852	5.404	7,905,823	8,804,023	427,100
November		OS	200,000		200,000	4.412	5.105	8,824,500	10,210,000	842,000
2005	St.Lucie Rel.		0		0	0.000	0.000	0	0	0
Total			200,000	0	200,000	4.412	5.105	8,824,500	10,210,000	842,000
December		OS	255,000		255,000	4.029	4.839	10,273,500	12,340,000	1,398,700
2005	St.Lucie Rel.		44,598		44,598	0.350	0.350	155,969	155,969	0
Total			299,598	0	299,598	3.481	4.171	10,429,469	12,495,969	1,398,700
Period		OS	2,460,000	0	2,460,000	4.685	5.421	115,254,050	133,365,000	11,084,350
	St.Lucie Rel.		448,894		448,894	0.314	0.314	1,408,227	1,408,227	0
Total			2,908,894	0	2,908,894	4.011	4.585	116,662,277	133,365,000	11,084,350

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005	Sou. Co. (UPS + R)		685,874			685,874	1.694		11,618,000
January	St. Lucie Rel.		46,084			46,084	0.334		154,000
	SJRPP		255,683			255,683	1.505		3,849,000
	PPAs		76,579			76,579	8.337		6,384,184
Total			1,064,220			1,064,220	2.068		22,005,184
2005	Sou. Co. (UPS + R)		602,046			602,046	1.694		10,199,000
February	St. Lucie Rel.		41,624			41,624	0.333		138,800
	SJRPP		226,015			226,015	1.505		3,402,000
	PPAs		62,399			62,399	8.001		4,992,775
Total			932,084			932,084	2.010		18,732,575
2005	Sou. Co. (UPS + R)		678,293			678,293	1.694		11,490,000
March	St. Lucie Rel.		46,084			46,084	0.333		153,400
	SJRPP		131,156			131,156	1.494		1,960,000
	PPAs		56,193			56,193	7.685		4,318,594
Total			911,726			911,726	1.966		17,921,994
2005	Sou. Co. (UPS + R)		667,634			667,634	1.694		11,310,000
April	St. Lucie Rel.		43,866			43,866	0.338		148,200
	SJRPP		127,848			127,848	1.473		1,883,000
	PPAs		14,658			14,658	7.094		1,039,867
Total			854,006			854,006	1.684		14,381,067
2005	Sou. Co. (UPS + R)		690,375			690,375	1.694		11,695,000
May	St. Lucie Rel.		45,328			45,328	0.337		152,900
	SJRPP		254,271			254,271	1.483		3,770,000
	PPAs		61,548			61,548	7.977		4,909,768
Total			1,051,522			1,051,522	1.952		20,527,668
2005	Sou. Co. (UPS + R)		668,159			668,159	1.694		11,318,000
June	St. Lucie Rel.		43,866			43,866	0.337		147,700
	SJRPP		249,689			249,689	1.483		3,702,000
	PPAs		12,680			12,680	8.339		1,057,415
Total			974,394			974,394	1.665		16,225,115
	Sou. Co. (UPS + R)		3,992,381			3,992,381	1.694		67,630,000
Period	St. Lucie Rel.		266,852			266,852	0.335		895,000
Total	SJRPP		1,244,662			1,244,662	1.492		18,566,000
	PPAs		284,057			284,057	7.992		22,702,603
Total			5,787,952			5,787,952	1.897		109,793,603

Date: 9/09/2004
Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2005 July	Sou. Co. (UPS + R)		682,882			682,882	1.694		11,568,000
	St. Lucie Rel.		45,328			45,328	0.337		152,700
	SJRPP		252,661			252,661	1.491		3,766,000
	PPAs		129,144			129,144	7.817		10,094,976
Total			1,110,015			1,110,015	2.305		25,581,676
2005 August	Sou. Co. (UPS + R)		684,561			684,561	1.694		11,597,000
	St. Lucie Rel.		45,328			45,328	0.336		152,500
	SJRPP		252,093			252,093	1.490		3,756,000
	PPAs		102,869			102,869	7.892		8,118,651
Total			1,084,851			1,084,851	2.178		23,624,151
2005 September	Sou. Co. (UPS + R)		666,249			666,249	1.694		11,286,000
	St. Lucie Rel.		43,866			43,866	0.336		147,300
	SJRPP		246,846			246,846	1.488		3,674,000
	PPAs		35,976			35,976	7.848		2,823,338
Total			992,937			992,937	1.806		17,930,638
2005 October	Sou. Co. (UPS + R)		690,431			690,431	1.694		11,696,000
	St. Lucie Rel.		45,328			45,328	0.335		151,900
	SJRPP		251,964			251,964	1.493		3,762,000
	PPAs		23,747			23,747	7.757		1,842,074
Total			1,011,470			1,011,470	1.725		17,451,974
2005 November	Sou. Co. (UPS + R)		666,812			666,812	1.694		11,296,000
	St. Lucie Rel.		44,597			44,597	0.135		60,000
	SJRPP		249,285			249,285	1.522		3,793,000
	PPAs		17,325			17,325	8.809		1,526,160
Total			978,019			978,019	1.705		16,675,160
2005 December	Sou. Co. (UPS + R)		666,170			666,170	1.694		11,285,000
	St. Lucie Rel.		46,084			46,084	0.329		151,400
	SJRPP		259,614			259,614	1.521		3,950,000
	PPAs		40,361			40,361	9.453		3,815,311
Total			1,012,229			1,012,229	1.897		19,201,711
Period Total	Sou. Co. (UPS + R)		8,049,486			8,049,486	1.694		136,358,000
	St. Lucie Rel.		537,383			537,383	0.318		1,710,800
	SJRPP		2,757,125			2,757,125	1.497		41,267,000
	PPAs		633,479			633,479	8.039		50,923,113
Total			11,977,473			11,977,473	1.922		230,258,913

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005 January	Qual. Facilities		626,975			626,975	2.217	2.217	13,899,000
Total			626,975			626,975	2.217	2.217	13,899,000
2005 February	Qual. Facilities		580,256			580,256	2.221	2.221	12,887,000
Total			580,256			580,256	2.221	2.221	12,887,000
2005 March	Qual. Facilities		627,218			627,218	2.217	2.217	13,908,000
Total			627,218			627,218	2.217	2.217	13,908,000
2005 April	Qual. Facilities		612,627			612,627	2.220	2.220	13,598,000
Total			612,627			612,627	2.220	2.220	13,598,000
2005 May	Qual. Facilities		626,456			626,456	2.223	2.223	13,924,000
Total			626,456			626,456	2.223	2.223	13,924,000
2005 June	Qual. Facilities		613,698			613,698	2.221	2.221	13,630,000
Total			613,698			613,698	2.221	2.221	13,630,000
Period Total	Qual. Facilities		3,687,230			3,687,230	2.220	2.220	81,846,000
Total			3,687,230			3,687,230	2.220	2.220	81,846,000

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Company: Florida Power & Light

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005 July	Qual. Facilities		625,600			625,600	2.205	2.205	13,796,000
Total			625,600			625,600	2.205	2.205	13,796,000
2005 August	Qual. Facilities		625,964			625,964	2.212	2.212	13,849,000
Total			625,964			625,964	2.212	2.212	13,849,000
2005 September	Qual. Facilities		613,260			613,260	2.219	2.219	13,609,000
Total			613,260			613,260	2.219	2.219	13,609,000
2005 October	Qual. Facilities		627,282			627,282	2.222	2.222	13,936,000
Total			627,282			627,282	2.222	2.222	13,936,000
2005 November	Qual. Facilities		518,322			518,322	2.253	2.253	11,677,000
Total			518,322			518,322	2.253	2.253	11,677,000
2005 December	Qual. Facilities		530,305			530,305	2.233	2.233	11,843,000
Total			530,305			530,305	2.233	2.233	11,843,000
Period Total	Qual. Facilities		7,227,963			7,227,963	2.221	2.221	160,556,000
Total			7,227,963			7,227,963	2.221	2.221	160,556,000

Date:9/09/2004
Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2005 Thru December 2005

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	January	Florida	C	94,000	3.366	3,164,213	5.071	4,767,010	1,602,797
2	2005	Non-Florida	C	42,036	4.830	2,030,522	5.170	2,173,261	142,739
3									
4	Total			136,036	3.819	5,194,735	5.102	6,940,271	1,745,536
5									
6									
7	February	Florida	C	87,000	3.372	2,933,213	5.080	4,419,450	1,486,237
8	2005	Non-Florida	C	37,968	4.834	1,835,258	5.232	1,986,486	151,228
9									
10	Total			124,968	3.816	4,768,471	5.126	6,405,936	1,637,465
11									
12									
13	March	Florida	C	94,000	3.457	3,249,213	5.113	4,806,310	1,557,097
14	2005	Non-Florida	C	44,913	4.757	2,136,499	5.248	2,357,034	220,535
15									
16	Total			138,913	3.877	5,385,712	5.157	7,163,344	1,777,632
17									
18									
19	April	Florida	C	92,000	3.548	3,264,213	5.037	4,634,500	1,370,287
20	2005	Non-Florida	C	57,048	4.667	2,662,589	5.132	2,927,703	265,114
21									
22	Total			149,048	3.976	5,926,802	5.074	7,562,203	1,635,401
23									
24									
25	May	Florida	C	94,000	3.547	3,334,213	5.089	4,783,650	1,449,437
26	2005	Non-Florida	C	58,950	4.665	2,750,081	5.154	3,038,283	288,202
27									
28	Total			152,950	3.978	6,084,294	5.114	7,821,933	1,737,639
29									
30									
31	June	Florida	C	13,000	4.900	637,000	5.188	674,440	37,440
32	2005	Non-Florida	C	43,464	4.759	2,068,396	5.188	2,254,912	186,516
33									
34	Total			56,464	4.791	2,705,396	5.188	2,929,352	223,956
35									
36									
37	Period	Florida	C	474,000	3.498	16,582,065	5.081	24,085,360	7,503,295
38	Total	Non-Florida	C	284,379	4.741	13,483,345	5.182	14,737,679	1,254,334
39									
40	Total			758,379	3.964	30,065,410	5.119	38,823,039	8,757,629
41									

Date:9/09/2004
Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2005 Thru December 2005

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	C	15,000	4.900	735,000	5.024	753,600	18,600
2	2005	Non-Florida	C	44,913	4.757	2,136,499	5.024	2,256,429	119,930
3									
4	Total			59,913	4.793	2,871,499	5.024	3,010,029	138,530
5									
6									
7	August	Florida	C	15,000	5.000	750,000	5.114	767,100	17,100
8	2005	Non-Florida	C	44,913	4.857	2,181,412	5.114	2,296,851	115,439
9									
10	Total			59,913	4.893	2,931,412	5.114	3,063,951	132,539
11									
12									
13	September	Florida	C	12,000	4.800	576,000	5.208	624,960	48,960
14	2005	Non-Florida	C	48,432	4.663	2,258,577	5.208	2,522,339	263,762
15									
16	Total			60,432	4.691	2,834,577	5.208	3,147,299	312,722
17									
18									
19	October	Florida	C	30,000	4.500	1,350,000	5.278	1,583,400	233,400
20	2005	Non-Florida	C	59,991	4.655	2,792,850	5.278	3,166,325	373,475
21									
22	Total			89,991	4.604	4,142,850	5.278	4,749,725	606,875
23									
24									
25	November	Florida	C	50,000	4.300	2,150,000	4.941	2,470,500	320,500
26	2005	Non-Florida	C	44,640	4.346	1,939,990	4.941	2,205,662	265,672
27									
28	Total			94,640	4.322	4,089,990	4.941	4,676,162	586,172
29									
30									
31	December	Florida	C	50,000	4.400	2,200,000	4.662	2,331,000	131,000
32	2005	Non-Florida	C	46,128	4.444	2,050,102	4.662	2,150,487	100,385
33									
34	Total			96,128	4.421	4,250,102	4.662	4,481,487	231,385
35									
36									
37	Period	Florida	C	646,000	3.768	24,343,065	5.049	32,615,920	8,272,855
38	Total	Non-Florida	C	573,396	4.681	26,842,775	5.116	29,335,772	2,492,997
39									
40	Total			1,219,396	4.198	51,185,840	5.081	61,951,692	10,765,852
41									

SCHEDULE E10

COMPANY: FLORIDA POWER & LIGHT COMPANY

	JAN 04 - DEC 04	PROPOSED JAN 05 - DEC 05	DIFFERENCE FROM CURRENT $	DIFFERENCE FROM CURRENT %
BASE	$40.22	$40.22	$0.00	0.00%
FUEL	$37.50	$40.09	$2.59	6.91%
CONSERVATION	$1.45	$1.48	$0.03	2.07%
CAPACITY PAYMENT	$6.25	$7.39	$1.14	18.24%
ENVIRONMENTAL	$0.13	$0.25	$0.12	92.31%
SUBTOTAL	$85.55	$89.43	$3.88	4.54%
GROSS RECEIPTS TAX	$0.88	$0.92	$0.04	4.55%
TOTAL	**$86.43**	**$90.35**	$3.92	4.54%

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC 2002 - 2002 (COLUMN 1)	JAN - DEC 2003 - 2003 (COLUMN 2)	JAN - DEC 2004 - 2004 (COLUMN 3)	JAN - DEC 2005 - 2005 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	993,639,285	669,789,553	844,089,611	768,560,945	(32.6)	26.0	(9.0)
2	LIGHT OIL	14,088,154	17,235,168	32,455,806	18,483,540	22.3	88.3	(43.1)
3	COAL	104,731,935	101,539,662	96,020,000	97,400,320	(3.1)	(5.4)	1.4
4	GAS	1,018,816,753	1,205,960,702	2,147,830,095	2,652,500,447	18.4	78.1	23.5
5	NUCLEAR	69,855,439	70,877,908	70,064,262	79,188,310	1.5	(1.2)	13.0
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	2,201,131,566	2,065,402,993	3,190,459,774	3,616,133,562	(6.2)	54.5	13.3
	SYSTEM NET GENERATION							
8	HEAVY OIL	25,802,011	18,708,283	19,071,313	15,612,822	(27.5)	1.9	(18.1)
9	LIGHT OIL	161,593	188,173	252,246	136,454	16.5	34.1	(45.9)
10	COAL	6,266,830	5,977,062	6,024,585	6,362,357	(4.6)	0.8	5.6
11	GAS	24,497,016	34,545,924	41,765,221	49,165,882	41.0	20.9	17.7
12	NUCLEAR	24,069,938	25,295,157	23,399,357	23,120,944	5.1	(7.5)	(1.2)
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	80,797,388	84,714,599	90,512,722	94,398,459	4.9	6.8	4.3
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	40,994,892	29,790,686	29,326,779	24,057,261	(27.3)	(1.6)	(18.0)
16	LIGHT OIL (Bbl)	381,359	472,694	615,405	337,765	24.0	30.2	(45.1)
17	COAL (TON)	772,666	760,021	703,887	3,219,277	(1.6)	(7.4)	357.4
18	GAS (MCF)	212,955,990	286,112,118	323,457,294	369,556,040	34.4	13.1	14.3
19	NUCLEAR (MMBTU)	262,850,564	276,217,616	256,425,934	257,760,861	5.1	(7.2)	0.5
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	260,958,241	190,168,594	187,396,213	153,966,465	(27.1)	(1.5)	(17.8)
22	LIGHT OIL	2,195,828	2,704,322	3,581,821	1,969,157	23.2	32.5	(45.0)
23	COAL	61,112,685	59,238,746	58,385,812	61,248,908	(3.1)	(1.4)	4.9
24	GAS	222,327,090	296,722,566	328,913,582	369,556,040	33.5	10.9	12.4
25	NUCLEAR	262,850,563	276,217,616	256,425,934	257,760,861	5.1	(7.2)	0.5
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	809,444,407	825,051,844	834,703,362	844,501,431	1.9	1.2	1.2
	GENERATION MIX (%MWH)							
28	HEAVY OIL	31.93	22.08	21.07	16.54	-	-	-
29	LIGHT OIL	0.20	0.22	0.28	0.14	-	-	-
30	COAL	7.76	7.06	6.66	6.74			
31	GAS	30.32	40.78	46.14	52.08	-	-	-
32	NUCLEAR	29.79	29.86	25.85	24.49	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	24.2381	22.4832	28.7822	31.9472	(7.2)	28.0	11.0
36	LIGHT OIL ($/Bbl)	36.9419	36.4615	52.7389	54.7231	(1.3)	44.6	3.8
37	COAL ($/TON)	34.7820	34.5097	38.7111	30.2553	(0.8)	12.2	(21.8)
38	GAS ($/MCF)	4.7842	4.2150	6.6402	7.1775	(11.9)	57.5	8.1
39	NUCLEAR ($/MMBTU)	0.2658	0.2566	0.2732	0.3072	(3.5)	6.5	12.5
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	3.8077	3.5221	4.5043	4.9917	(7.5)	27.9	10.8
42	LIGHT OIL	6.4159	6.3732	9.0613	9.3865	(0.7)	42.2	3.6
43	COAL	1.7138	1.7141	1.6446	1.5902	0.0	(4.1)	(3.3)
44	GAS	4.5825	4.0643	6.5301	7.1775	(11.3)	60.7	9.9
45	NUCLEAR	0.2658	0.2566	0.2732	0.3072	(3.5)	6.5	12.5
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	2.7193	2.5034	3.8223	4.2820	(7.9)	52.7	12.0
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,114	10,165	9,826	9,862	0.5	(3.3)	0.4
49	LIGHT OIL	13,589	14,371	14,200	14,431	5.8	(1.2)	1.6
50	COAL	9,752	9,911	9,691	9,627	1.6	(2.2)	(0.7)
51	GAS	9,076	8,589	7,875	7,517	(5.4)	(8.3)	(4.6)
52	NUCLEAR	10,920	10,920	10,959	11,148	0.0	0.4	1.7
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	10,018	9,739	9,222	8,946	(2.8)	(5.3)	(3.0)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	3.8510	3.5802	4.4260	4.9226	(7.0)	23.6	11.2
56	LIGHT OIL	8.7183	9.1592	12.8657	13.5456	5.1	40.5	5.3
57	COAL	1.6712	1.6988	1.5938	1.5309	1.7	(6.2)	(4.0)
58	GAS	4.1589	3.4909	5.1426	5.3950	(16.1)	47.3	4.9
59	NUCLEAR	0.2902	0.2802	0.2994	0.3425	(3.5)	6.9	14.4
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	2.7243	2.4381	3.5249	3.8307	(10.5)	44.6	8.7

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next five periods are as follows. In addition, As-Available Energy cost payments will include .0001¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2004 – March 31, 2005	5.41	4.58	4.82
April 1, 2005 – September 30, 2005	4.90	4.67	4.74
October 1, 2005 – March 31, 2006	4.84	4.16	4.36
April 1, 2006 – September 30, 2006	4.71	4.44	4.52
October 1, 2006 – March 31, 2007	4.66	4.06	4.24
April 1, 2007 – September 30, 2007	4.58	4.31	4.39

A MW block size ranging from 36 MW to 40 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0217
Secondary Voltage Delivery	1.0473

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2005	21	15	45	6	14	.29	3.94	5.52	1.55
2006	21	13	47	5	14	.28	3.91	5.43	1.58
2007	20	12	49	6	13	.29	3.90	5.43	1.61
2008	21	11	50	5	13	.30	4.03	5.44	1.62
2009	20	10	52	5	13	.39	4.16	5.56	1.63
2010	19	10	57	5	9	.40	4.36	5.61	1.66
2011	19	9	60	5	6	.40	4.36	5.75	1.69
2012	19	7	64	5	6	.41	4.61	5.85	1.72
2013	18	7	64	5	6	.42	4.88	6.02	1.75

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.37	CST-1	102.27
GST-1	11.44	GSLD-2	158.05
GSD-1	32.54	GSLDT-2	158.05
GSDT-1	38.58	CS-2	158.05
RS-1	5.25	CST-2	158.05
RST-1	8.32	GSLD-3	371.88
GSLD-1	38.12	CS-3	371.88
GSLDT-1	38.12	CST-3	371.88
CS-1	102.27	GSLDT-3	371.88

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.155%
Distribution Equipment	0.251%
Transmission Equipment	0.104%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 040001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-5
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 10
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-6)
DATE: 11-08-04

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
3	Projected Capacity Payments	K. M. Dubin
4	Calculation of Energy & Demand Allocation % By Rate Class	K. M. Dubin
5	Calculation of Capacity Recovery Factor	K. M. Dubin

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2005 THROUGH DECEMBER 2005

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$189,483,480
2. SHORT TERM CAPACITY PAYMENTS	$5,850,235	$5,850,235	$3,576,215	$3,485,965	$5,984,725	$11,272,940	$11,272,940	$11,272,940	$5,803,850	$1,446,505	$1,726,745	$3,703,645	$71,226,940
3. CAPACITY PAYMENTS TO COGENERATORS	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,823,832	$30,823,832	$30,823,832	$30,823,832	$25,046,008	$25,046,008	$353,802,166
4a. SJRPP SUSPENSION ACCRUAL	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$4,718,484
4b. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($346,104)	($349,955)	($353,805)	($357,656)	($361,506)	($365,357)	($369,207)	($373,058)	($376,908)	($380,759)	($384,609)	($388,460)	($4,407,384)
5b. OKEELANTA SETTLEMENT	$3,005,887	$3,002,640	$2,999,393	$2,996,146	$2,992,899	$2,989,652	$2,986,405	$2,983,158	$2,979,911	$2,976,664	$2,973,417	$2,970,170	$35,856,342
6. INCREMENTAL PLANT SECURITY COSTS	$1,175,804	$1,175,804	$1,175,804	$1,175,804	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$12,482,363
7. TRANSMISSION OF ELECTRICITY BY OTHERS	$624,947	$633,552	$630,309	$640,087	$601,573	$603,462	$507,849	$523,390	$582,789	$591,944	$598,537	$579,780	$7,118,219
8. TRANSMISSION REVENUES FROM CAPACITY SALES	($704,000)	($676,850)	($613,500)	($481,750)	($436,500)	($642,500)	($607,900)	($607,900)	($573,300)	($471,100)	($543,500)	($667,800)	($7,026,600)
9. SYSTEM TOTAL	$55,859,403	$55,888,060	$53,667,050	$53,691,230	$56,006,218	$61,083,224	$61,769,809	$61,778,252	$56,396,064	$52,142,976	$46,572,488	$48,399,234	$663,254,010
10. JURISDICTIONAL % *													98.63289%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$654,186,598
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2003 - DECEMBER 2003 ($7,050,083)		EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2004 - DECEMBER 2004 ($73,892,873)											($80,942,956)
14. TOTAL (Lines 11+12-13)													$678,183,962
15. REVENUE TAX MULTIPLIER													1.01597
16. TOTAL RECOVERABLE CAPACITY PAYMENTS													$689,014,560

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	17,676	98.63289%
FERC	245	1.36711%
TOTAL	17,921	100.00000%

* BASED ON 2003 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2005 THROUGH DECEMBER 2005

Rate Schedule	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1/RST1	63.060%	55,334,940,634	10,017,085	1.09230267	1.07281827	59,364,335,282	10,941,689	53.79073%	59.77947%
GS1/GST1	69.973%	6,075,542,153	991,175	1.09230267	1.07281827	6,517,952,622	1,082,663	5.90599%	5.91508%
GSD1/GSDT1	77.702%	23,085,553,190	3,391,595	1.09220064	1.07274057	24,764,809,488	3,704,302	22.43969%	20.23830%
OS2	93.228%	21,113,200	2,585	1.05829225	1.04657532	22,096,554	2,736	0.02002%	0.01495%
GSLD1/GSLDT1/CS1/CST1	83.923%	10,666,361,079	1,450,879	1.09083728	1.07170069	11,431,146,528	1,582,673	10.35790%	8.64687%
GSLD2/GSLDT2/CS2/CST2	87.158%	1,750,619,663	229,288	1.08297958	1.06544968	1,865,197,160	248,314	1.69008%	1.35665%
GSLD3/GSLDT3/CS3/CST3	86.580%	187,194,635	24,682	1.02969493	1.02438901	191,760,127	25,415	0.17376%	0.13885%
ISST1D	96.676%	0	0	1.09230267	1.07281827	0	0	0.00000%	0.00000%
ISST1T	87.151%	0	0	1.02969493	1.02438901	0	0	0.00000%	0.00000%
SST1T	87.151%	150,031,028	19,652	1.02969493	1.02438901	153,690,136	20,236	0.13926%	0.11056%
SST1D1/SST1D2/SST1D3	96.676%	23,594,871	2,786	1.07224837	1.06763473	25,190,703	2,987	0.02283%	0.01632%
CILC D/CILC G	92.072%	3,469,946,584	430,221	1.08128023	1.06432600	3,693,154,368	465,189	3.34641%	2.54154%
CILC T	94.419%	1,522,653,717	184,093	1.02969493	1.02438901	1,559,789,734	189,560	1.41334%	1.03565%
MET	70.123%	96,643,843	15,733	1.05829225	1.04657532	101,145,061	16,650	0.09165%	0.09097%
OL1/SL1/PL1	565.360%	555,624,734	11,219	1.09230267	1.07281827	596,084,366	12,255	0.54012%	0.06695%
SL2	99.953%	70,174,667	8,015	1.09230267	1.07281827	75,284,665	8,755	0.06822%	0.04783%
TOTAL		103,009,994,000	16,779,008			110,361,636,794	18,303,424	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2005 through December 2005.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2003 demand losses.
(5) Based on 2003 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2005 THROUGH DECEMBER 2005

Rate Schedule	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1/RST1	53.79073%	59.77947%	$28,509,692	$380,205,434	$408,715,126	55,334,940,634	-	-	-	0.00739
GS1/GST1	5.90599%	5.91508%	$3,130,243	$37,620,733	$40,750,976	6,075,542,153	-	-	-	0.00671
GSD1/GSDT1	22.43969%	20.23830%	$11,893,287	$128,718,313	$140,611,600	23,085,553,190	49.73909%	52,939,773	2.66	-
OS2	0.02002%	0.01495%	$10,612	$95,071	$105,683	21,113,200	-	-	-	0.00501
GSLD1/GSLDT1/CS1/CST1	10.35790%	8.64687%	$5,489,802	$54,995,246	$60,485,048	10,666,361,079	64.68915%	22,587,178	2.68	-
GSLD2/GSLDT2/CS2/CST2	1.69008%	1.35665%	$895,760	$8,628,497	$9,524,257	1,750,619,663	66.01990%	3,632,403	2.62	-
GSLD3/GSLDT3/CS3/CST3	0.17376%	0.13885%	$92,093	$883,129	$975,222	187,194,635	70.45754%	363,951	2.68	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.13926%	0.11056%	$73,810	$703,167	$776,977	150,031,028	19.42328%	1,058,122	**	-
SST1D1/SST1D2/SST1D3	0.02283%	0.01632%	$12,098	$103,793	$115,891	23,594,871	63.51414%	50,889	**	-
CILC D/CILC G	3.34641%	2.54154%	$1,773,636	$16,164,541	$17,938,177	3,469,946,584	74.11221%	6,413,722	2.80	-
CILC T	1.41334%	1.03565%	$749,088	$6,586,894	$7,335,982	1,522,653,717	78.45936%	2,658,481	2.76	-
MET	0.09165%	0.09097%	$48,575	$578,560	$627,135	96,643,843	58.55491%	226,093	2.77	-
OL1/SL1/PL1	0.54012%	0.06695%	$286,269	$425,841	$712,110	555,624,734	-	-	-	0.00128
SL2	0.06822%	0.04783%	$36,155	$304,222	$340,377	70,174,667	-	-	-	0.00485
TOTAL			$53,001,120	$636,013,440	$689,014,560	103,009,994,000		89,930,612		

Note:There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2005 through December 2005
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

	CAPACITY RECOVERY FACTOR	
	RDC	SDD
	** ($/kw)	** ($/kw)
ISST1D	$0.34	$0.16
ISST1T	$0.32	$0.15
SST1T	$0.32	$0.15
SST1D1/SST1D2/SST1D3	$0.34	$0.16

DOCUMENT NO. 1

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2003

PS -1
DOCKET NO. 040001-EI
FPL Witness: Pamela Sonnelitter
Exhibit No.: _____
Pages 1 - 23
April 1, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 11
COMPANY/ FP+L
WITNESS. P. Sonnelitter (PS-1)
DATE 11-08-04

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2003

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	6.203.001	Index of Manual Pages
	6.203.002	GPIF Reward/(Penalty) Table (Actual)
	6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
	6.203.004	Derivation of System Actual GPIF Points
	6.203.005	Actual Equivalent Availability and Adjustments Summary
	6.203.006	EAF Adjustment Documentation
	6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
	6.203.008 - 6.203.022	GPIF Units Points Tables
	6.203.023	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2003

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+ 10		59,205.40		22,901.40
+ 9		53,284.86		20,611.26
+ 8		47,364.32		18,321.12
+ 7		41,443.78		16,030.98
+ 6		35,523.24		13,740.84
+ 5		29,602.70		11,450.70
+ 4		23,682.16		9,160.56
+ 3	<---------- 2.89	17,761.62	6,615.282 ---------->	6,870.42
+ 2		11,841.08		4,580.28
+ 1		5,920.54		2,290.14
0		0.00		0.00
- 1		(6,121.84)		(2,290.14)
- 2		(12,243.68)		(4,580.28)
- 3		(18,365.52)		(6,870.42)
- 4		(24,487.36)		(9,160.56)
- 5		(30,609.20)		(11,450.70)
- 6		(36,731.04)		(13,740.84)
- 7		(42,852.88)		(16,030.98)
- 8		(48,974.72)		(18,321.12)
- 9		(55,096.56)		(20,611.26)
- 10		(61,218.40)		(22,901.40)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2003

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,381,760,459	
LINE 2	MONTH OF January	2003	$ 5,443,518,178	
LINE 3	MONTH OF February	2003	$ 5,416,795,989	
LINE 4	MONTH OF March	2003	$ 5,420,129,425	
LINE 5	MONTH OF April	2003	$ 5,429,749,346	
LINE 6	MONTH OF May	2003	$ 5,453,701,108	
LINE 7	MONTH OF June	2003	$ 5,460,622,288	
LINE 8	MONTH OF July	2003	$ 5,479,432,897	
LINE 9	MONTH OF August	2003	$ 5,472,758,595	
LINE 10	MONTH OF September	2003	$ 6,070,337,187	
LINE 11	MONTH OF October	2003	$ 6,046,590,185	
LINE 12	MONTH OF November	2003	$ 6,013,601,919	
LINE 13	MONTH OF December	2003	$ 6,004,027,910	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,622,540,421	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 23,249,240	
LINE 18	JURISDICTIONAL SALES		99,495,660,000	KWH
LINE 19	TOTAL SALES		101,006,875,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.50%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$ 22,901,397	

JANUARY THROUGH DECEMBER, 2003

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 2	EAF	0.50	0.00	.0000
Cape Canaveral 2	ANOHR	2.65	0.00	.0000
Lauderdale 4	EAF	0.90	6.40	.0576
Lauderdale 4	ANOHR	3.13	0.00	.0000
Lauderdale 5	EAF	1.01	9.60	.0971
Lauderdale 5	ANOHR	3.76	0.00	.0000
Manatee 2	EAF	0.43	10.00	.0431
Manatee 2	ANOHR	2.88	0.00	.0000
Martin 1	EAF	0.30	10.00	.0297
Martin 1	ANOHR	4.51	0.52	.0234
Martin 2	EAF	0.38	10.00	.0378
Martin 2	ANOHR	5.72	0.00	.0000
Martin 3	EAF	1.34	-10.00	-.1337
Martin 3	ANOHR	1.31	-10.00	-.1313
Martin 4	EAF	1.02	-10.00	-.1015
Martin 4	ANOHR	1.50	-8.49	-.1274
Turkey Point 1	EAF	0.37	4.80	.0179
Turkey Point 1	ANOHR	2.92	0.00	.0000
Turkey Point 2	EAF	0.34	-8.00	-.0274
Turkey Point 2	ANOHR	1.94	0.85	.0165
Turkey Point 3	EAF	9.38	8.67	.8128
Turkey Point 3	ANOHR	5.00	0.00	.0000
Turkey Point 4	EAF	9.41	10.00	.9406
Turkey Point 4	ANOHR	5.35	0.00	.0000
St. Lucie 1	EAF	12.23	10.00	1.2231
St. Lucie 1	ANOHR	1.97	0.00	.0000
St. Lucie 2	EAF	9.65	0.67	.0643
St. Lucie 2	ANOHR	3.28	0.00	.0000
Scherer 4	EAF	3.83	1.20	.0460
Scherer 4	ANOHR	2.99	0.00	.0000
GPIF System Total:		100.00		2.89

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2003

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO	ADJUSTED ACTUAL		POINTS FROM	ORIGINAL PLANNED		ACTUAL FUEL SAVINGS/ (LOSS)
UNIT	FOF	MOF	POF	EAF	EA (1)	EA	TARGET EA	TABLES	DATES	ACTUAL DATES	($000)
Cape Canaveral 2	1.7	8.0	7.0	83.2	0.0	89.5	89.5	0.00	-	11/29/2003 - 12/24/2003	0.0
Lauderdale 4	2.1	1.8	4.6	91.5	1.6	93.3	91.7	6.40	04/05/03 - 04/14/03	04/04/2003 - 04/28/2003	341.0
Lauderdale 5	0.1	4.4	4.0	91.5	2.4	92.7	90.3	9.60	10/11/03 - 10/20/03	10/26/2003 - 11/07/2003	574.9
Manatee 2	0.0	1.3	0.0	98.7	3.4	91.1	87.7	10.00	04/26/03 - 05/23/03	NONE	254.9
Martin 1	0.2	0.1	10.6	89.2	4.1	95.9	91.8	10.00	10/18/03 - 10/31/03	4/14/03 - 5/2/03 and 11/2/03 - 11/23/03	175.9
Martin 2	0.4	3.3	7.0	89.4	3.4	86.9	83.5	10.00	11/01/03 - 12/05/03	11/24/2003 - 12/19/2003	223.9
Martin 3	8.3	12.6	0.9	78.1	-15.8	77.0	92.8	-10.00	04/12/03 - 04/17/03	02/16/2003 - 02/22/2003	(791.3)
Martin 4	0.3	9.0	6.3	84.4	-5.7	88.1	93.8	-10.00	10/18/03 - 10/27/03	10/30/2003 - 12/16/2003	(601.2)
Turkey Point 1	1.9	1.8	17.8	78.5	1.2	86.3	85.1	4.80	03/08/03 - 04/11/03	02/14/2003 - 04/20/2003	106.0
Turkey Point 2	1.5	5.2	0.0	93.3	-1.6	93.3	94.9	-8.00	-	NONE	(162.0)
Turkey Point 3	3.8	0.0	8.6	87.6	2.6	88.0	85.4	8.67	03/03/03 - 04/02/03	03/01/2003 - 03/28/2003	4,812.3
Turkey Point 4	0.0	0.0	10.2	89.8	6.4	91.8	85.4	10.00	10/06/03 - 11/05/03	10/01/2003 - 11/05/2003	5,568.7
St. Lucie 1	0.0	0.0	0.0	100.0	6.4	100.0	93.6	10.00	-	NONE	7,241.6
St. Lucie 2	5.8	0.0	14.3	80.0	0.2	85.6	85.4	0.67	04/21/03 - 05/21/03	04/20/2003 - 06/11/2003	380.9
Scherer 4	3.1	3.0	0.0	93.9	0.3	93.9	93.6	1.20	-	NONE	272.2
											18,397.8

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGETED DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2003

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	POH	EAF%
Cape Canaveral 2	8760	152.1	699.6	615.9	0.0	0.0	89.5
Lauderdale 4	8760	186.2	157.8	399.3	2.7	236.5	93.3
Lauderdale 5	8760	10.2	386.0	351.1	2.7	236.5	92.7
Manatee 2	8760	2.7	113.0	0.0	7.7	674.5	91.1
Martin 1	8760	18.0	4.8	927.7	3.8	332.9	95.9
Martin 2	8760	33.5	285.6	610.2	9.6	841.0	86.9
Martin 3	8760	722.9	1120.5	78.3	2.2	192.7	77.0
Martin 4	8760	25.2	789.8	553.5	2.2	192.7	88.1
Turkey Point 1	8760	165.0	159.1	1562.7	9.6	841.0	86.3
Turkey Point 2	8760	130.4	454.4	0.0	0.0	0.0	93.3
Turkey Point 3	8760	333.9	0.0	749.0	8.2	718.3	88.0
Turkey Point 4	8760	0.0	0.0	893.6	8.2	718.3	91.8
St. Lucie 1	8760	0.1	0.0	0.9	0.0	0.0	100.0
St. Lucie 2	8760	505.9	0.0	1249.1	8.2	718.3	85.6
Scherer 4	8760	275.7	260.8	0.0	0.0	0.0	93.9

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - POH_T}{PH - POH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2003

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET (2)	ADJUST.(3)		ADJUST.(5)		ACTUAL
UNIT	HEAT RATE (1) FORMULA	NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET (4) ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	GPIF(6) FROM TABLE	FUEL SAV./(LOSS) $000
Cape Canaveral 2	ANOHR= -22.73 x NOF + 11158	64.9	9696	9682	14	9030	9044	0.00	0.0
Lauderdale 4	ANOHR= -14.39 x NOF + 8796	83.3	7617	7598	19	7435	7454	0.00	0.0
Lauderdale 5	ANOHR= -11.86 x NOF + 8522	82.5	7593	7543	50	7366	7416	0.00	0.0
Manatee 2	ANOHR= -13.04 x NOF + 11034	59.9	10279	10253	26	9862	9888	0.00	0.0
Martin 1	ANOHR= -18.05 x NOF + 11133	56.3	10024	10117	-93	9546	9453	0.52	138.3
Martin 2	ANOHR= -14.40 x NOF + 10872	53.4	10047	10103	-56	9590	9534	0.00	0.0
Martin 3	ANOHR= -1.66 x NOF + 6977	83.4	7018	6838	180	6829	7009	-10.00	(777.4)
Martin 4	ANOHR= -1.81 x NOF + 6918	81.6	6920	6770	150	6753	6903	-8.49	(754.2)
Turkey Point 1	ANOHR= -16.39 x NOF + 10685	64.5	9691	9628	63	9128	9191	0.00	0.0
Turkey Point 2	ANOHR= -7.22 x NOF + 10200	64.3	9647	9735	-88	9512	9424	0.85	97.5
Turkey Point 3	ANOHR= -33.17 x NOF + 14395	99.2	11040	11104	-64	11148	11084	0.00	0.0
Turkey Point 4	ANOHR= -25.79 x NOF + 13650	100.0	11083	11070	13	11119	11132	0.00	0.0
St. Lucie 1	ANOHR= -24.39 x NOF + 13249	102.1	10750	10760	-10	10834	10824	0.00	0.0
St. Lucie 2	ANOHR= -14.93 x NOF + 12323	98.9	10881	10846	35	10843	10878	0.00	0.0
Scherer 4	ANOHR= -19.65 x NOF + 11911	86.2	10184	10218	-34	9992	9958	0.00	0.0

(1295.8)

1) THESE FORMULAS ARE AS APPROVED BY THE COMMSION IN THE PROJECTED DATA AND REFLECT ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM GPIF POINTS TABLES AS APPROVED BY THE COMMISION IN PROJECTED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Cape Canaveral 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	293.70	92.5		+10	1569.55	8722	
+9	264.33	92.2		+9	1412.59	8745	
+8	234.96	91.9		+8	1255.64	8768	
+7	205.59	91.6		+7	1098.68	8792	
+6	176.22	91.3		+6	941.73	8815	
+5	146.85	91.0		+5	784.77	8838	
+4	117.48	90.7		+4	627.82	8862	
+3	88.11	90.4		+3	470.86	8885	
+2	58.74	90.1		+2	313.91	8908	
+1	29.37	89.8		+1	156.95	8931	
					0.00	8955	
0	0.00	89.5	<- Adj. Act. EAF= 89.5	0	0.00	9030	<- Adj. Act. HR=9044
					(0.00)	9105	
-1	(-29.37)	89.2		-1	(-156.95)	9128	
-2	(-58.74)	88.9		-2	(-313.91)	9151	
-3	(-88.11)	88.6		-3	(-470.86)	9175	
-4	(-117.48)	88.3		-4	(-627.82)	9198	
-5	(-146.85)	88.0		-5	(-784.77)	9221	
-6	(-176.22)	87.7		-6	(-941.73)	9245	
-7	(-205.59)	87.4		-7	(-1098.68)	9268	
-8	(-234.96)	87.1		-8	(-1255.64)	9291	
-9	(-264.33)	86.8		-9	(-1412.59)	9315	
-10	(-293.70)	86.5		-10	(-1569.55)	9338	
	WEIGHTING FACTOR =	0.50			WEIGHTING FACTOR =	2.65	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Lauderdale 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	532.83	94.2		+10	1850.55	7190	
+9	479.54	94.0		+9	1665.50	7207	
+8	426.26	93.7		+8	1480.44	7224	
+7	372.98	93.5		+7	1295.39	7241	
+6	319.70	93.2	<- Adj. Act. EAF= 93.3	+6	1110.33	7258	
+5	266.41	93.0		+5	925.28	7275	
+4	213.13	92.7		+4	740.22	7292	
+3	159.85	92.5		+3	555.17	7309	
+2	106.57	92.2		+2	370.11	7326	
+1	53.28	92.0		+1	185.06	7343	
					0.00	7360	
0	0.00	91.7		0	0.00	7435	<- Adj. Act. HR=7454
					(0.00)	7510	
-1	(-53.28)	91.5		-1	(-185.06)	7526	
-2	(-106.57)	91.2		-2	(-370.11)	7543	
-3	(-159.85)	91.0		-3	(-555.17)	7560	
-4	(-213.13)	90.7		-4	(-740.22)	7577	
-5	(-266.41)	90.5		-5	(-925.28)	7594	
-6	(-319.70)	90.2		-6	(-1110.33)	7611	
-7	(-372.98)	90.0		-7	(-1295.39)	7628	
-8	(-426.26)	89.7		-8	(-1480.44)	7645	
-9	(-479.54)	89.5		-9	(-1665.50)	7662	
-10	(-532.83)	89.2		-10	(-1850.55)	7679	
	WEIGHTING FACTOR =	0.90			WEIGHTING FACTOR =	3.13	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Lauderdale 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	598.82	92.8		+10	2226.62	7109	
+9	538.94	92.6	<- Adj. Act. EAF= 92.7	+9	2003.96	7128	
+8	479.05	92.3		+8	1781.30	7146	
+7	419.17	92.1		+7	1558.64	7164	
+6	359.29	91.8		+6	1335.97	7182	
+5	299.41	91.6		+5	1113.31	7200	
+4	239.53	91.3		+4	890.65	7218	
+3	179.65	91.1		+3	667.99	7236	
+2	119.76	90.8		+2	445.32	7254	
+1	59.88	90.6		+1	222.66	7272	
					0.00	7291	
0	0.00	90.3		0	0.00	7366	<- Adj. Act. HR=7416
					(0.00)	7441	
-1	(-59.88)	90.1		-1	(-222.66)	7459	
-2	(-119.76)	89.8		-2	(-445.32)	7477	
-3	(-179.65)	89.6		-3	(-667.99)	7495	
-4	(-239.53)	89.3		-4	(-890.65)	7513	
-5	(-299.41)	89.1		-5	(-1113.31)	7531	
-6	(-359.29)	88.8		-6	(-1335.97)	7549	
-7	(-419.17)	88.6		-7	(-1558.64)	7567	
-8	(-479.05)	88.3		-8	(-1781.30)	7585	
-9	(-538.94)	88.1		-9	(-2003.96)	7603	
-10	(-598.82)	87.8		-10	(-2226.62)	7622	
	WEIGHTING FACTOR =	1.01			WEIGHTING FACTOR =	3.76	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Manatee 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	254.94	89.7	<- Adj. Act. EAF= 91.1	+10	1705.88	9607	
+9	229.45	89.5		+9	1535.29	9625	
+8	203.95	89.3		+8	1364.71	9643	
+7	178.46	89.1		+7	1194.12	9661	
+6	152.96	88.9		+6	1023.53	9679	
+5	127.47	88.7		+5	852.94	9697	
+4	101.98	88.5		+4	682.35	9715	
+3	76.48	88.3		+3	511.76	9733	
+2	50.99	88.1		+2	341.18	9751	
+1	25.49	87.9		+1	170.59	9769	
					0.00	9787	
0	0.00	87.7		0	0.00	9862	<- Adj. Act. HR=9868
					(0.00)	9937	
-1	(-25.49)	87.5		-1	(-170.59)	9955	
-2	(-50.99)	87.3		-2	(-341.18)	9973	
-3	(-76.48)	87.1		-3	(-511.76)	9991	
-4	(-101.98)	86.9		-4	(-682.35)	10009	
-5	(-127.47)	86.7		-5	(-852.94)	10027	
-6	(-152.96)	86.5		-6	(-1023.53)	10045	
-7	(-178.46)	86.3		-7	(-1194.12)	10063	
-8	(-203.95)	86.1		-8	(-1364.71)	10081	
-9	(-229.45)	85.9		-9	(-1535.29)	10099	
-10	(-254.94)	85.7		-10	(-1705.88)	10117	
	WEIGHTING FACTOR =	0.43			WEIGHTING FACTOR =	2.88	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	175.92	93.8	<- Adj. Act. EAF= 95.9	+10	2671.26	9124	
+9	158.33	93.6		+9	2404.13	9158	
+8	140.74	93.4		+8	2137.01	9193	
+7	123.15	93.2		+7	1869.88	9228	
+6	105.55	93.0		+6	1602.76	9263	
+5	87.96	92.8		+5	1335.63	9297	
+4	70.37	92.6		+4	1068.50	9332	
+3	52.78	92.4		+3	801.38	9367	
+2	35.18	92.2		+2	534.25	9402	
+1	17.59	92.0		+1	267.13	9437	<- Adj. Act. HR=9453
					0.00	9471	
0	0.00	91.8		0	0.00	9546	
					(0.00)	9621	
-1	(-17.59)	91.6		-1	(-338.66)	9656	
-2	(-35.18)	91.4		-2	(-677.32)	9691	
-3	(-52.78)	91.2		-3	(-1015.98)	9726	
-4	(-70.37)	91.0		-4	(-1354.64)	9760	
-5	(-87.96)	90.8		-5	(-1693.30)	9795	
-6	(-105.55)	90.6		-6	(-2031.96)	9830	
-7	(-123.15)	90.4		-7	(-2370.62)	9865	
-8	(-140.74)	90.2		-8	(-2709.28)	9899	
-9	(-158.33)	90.0		-9	(-3047.94)	9934	
-10	(-175.92)	89.8		-10	(-3386.60)	9969	
	WEIGHTING FACTOR =	0.30			WEIGHTING FACTOR =	4.51	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	223.86	86.0	<- Adj. Act. EAF= 86.9	+10	3386.60	9160	
+9	201.47	85.8		+9	3047.94	9195	
+8	179.09	85.5		+8	2709.28	9231	
+7	156.70	85.3		+7	2370.62	9266	
+6	134.32	85.0		+6	2031.96	9302	
+5	111.93	84.8		+5	1693.30	9337	
+4	89.54	84.5		+4	1354.64	9373	
+3	67.16	84.3		+3	1015.98	9408	
+2	44.77	84.0		+2	677.32	9444	
+1	22.39	83.8		+1	338.66	9479	
					0.00	9515	<- Adj. Act. HR=9534
0	0.00	83.5		0	0.00	9590	
					(0.00)	9665	
-1	(-22.39)	83.3		-1	(-338.66)	9700	
-2	(-44.77)	83.0		-2	(-677.32)	9736	
-3	(-67.16)	82.8		-3	(-1015.98)	9771	
-4	(-89.54)	82.5		-4	(-1354.64)	9807	
-5	(-111.93)	82.3		-5	(-1693.30)	9843	
-6	(-134.32)	82.0		-6	(-2031.96)	9878	
-7	(-156.70)	81.8		-7	(-2370.62)	9914	
-8	(-179.09)	81.5		-8	(-2709.28)	9949	
-9	(-201.47)	81.3		-9	(-3047.94)	9985	
-10	(-223.86)	81.0		-10	(-3386.60)	10020	
	WEIGHTING FACTOR =	0.38			WEIGHTING FACTOR =	5.72	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	791.31	95.3		+10	777.42	6682	
+9	712.18	95.1		+9	699.68	6689	
+8	633.05	94.8		+8	621.94	6696	
+7	553.92	94.6		+7	544.20	6703	
+6	474.79	94.3		+6	466.45	6710	
+5	395.65	94.1		+5	388.71	6718	
+4	316.52	93.8		+4	310.97	6725	
+3	237.39	93.6		+3	233.23	6732	
+2	158.26	93.3		+2	155.48	6739	
+1	79.13	93.1		+1	77.74	6746	
					0.00	6754	
0	0.00	92.8		0	0.00	6829	
					(0.00)	6904	
-1	(-79.13)	92.6		-1	(-77.74)	6911	
-2	(-158.26)	92.3		-2	(-155.48)	6918	
-3	(-237.39)	92.1		-3	(-233.23)	6925	
-4	(-316.52)	91.8		-4	(-310.97)	6932	
-5	(-395.65)	91.6		-5	(-388.71)	6939	
-6	(-474.79)	91.3		-6	(-466.45)	6947	
-7	(-553.92)	91.1		-7	(-544.20)	6954	
-8	(-633.05)	90.8		-8	(-621.94)	6961	
-9	(-712.18)	90.6		-9	(-699.68)	6968	
-10	(-791.31)	90.3	<- Adj. Act. EAF= 77.0	-10	(-777.42)	6975	<- Adj. Act. HR=7009
	WEIGHTING FACTOR =	1.34			WEIGHTING FACTOR =	1.31	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	601.20	95.8		+10	888.67	6590	
+9	541.08	95.6		+9	799.80	6599	
+8	480.96	95.4		+8	710.94	6608	
+7	420.84	95.2		+7	622.07	6617	
+6	360.72	95.0		+6	533.20	6625	
+5	300.60	94.8		+5	444.33	6634	
+4	240.48	94.6		+4	355.47	6643	
+3	180.36	94.4		+3	266.60	6652	
+2	120.24	94.2		+2	177.73	6661	
+1	60.12	94.0		+1	88.87	6670	
					0.00	6678	
0	0.00	93.8		0	0.00	6753	
					(0.00)	6828	
-1	(-60.12)	93.6		-1	(-88.87)	6837	
-2	(-120.24)	93.4		-2	(-177.73)	6846	
-3	(-180.36)	93.2		-3	(-266.60)	6855	
-4	(-240.48)	93.0		-4	(-355.47)	6864	
-5	(-300.60)	92.8		-5	(-444.33)	6873	
-6	(-360.72)	92.6		-6	(-533.20)	6881	
-7	(-420.84)	92.4		-7	(-622.07)	6890	
-8	(-480.96)	92.2		-8	(-710.94)	6899	<- Adj. Act. HR=6903
-9	(-541.08)	92.0		-9	(-799.80)	6908	
-10	(-601.20)	91.8	<- Adj. Act. EAF= 88.1	-10	(-888.67)	6917	
	WEIGHTING FACTOR =	1.02			WEIGHTING FACTOR =	1.50	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	220.85	87.6		+10	1727.72	8763	
+9	198.77	87.4		+9	1554.95	8792	
+8	176.68	87.1		+8	1382.18	8821	
+7	154.60	86.9		+7	1209.41	8850	
+6	132.51	86.6		+6	1036.63	8879	
+5	110.43	86.4		+5	863.86	8908	
+4	88.34	86.1	<- Adj. Act. EAF= 86.3	+4	691.09	8937	
+3	66.26	85.9		+3	518.32	8966	
+2	44.17	85.6		+2	345.54	8995	
+1	22.09	85.4		+1	172.77	9024	
					0.00	9053	
0	0.00	85.1		0	0.00	9128	<- Adj. Act. HR=9191
					(0.00)	9203	
-1	(-22.09)	84.9		-1	(-172.77)	9232	
-2	(-44.17)	84.6		-2	(-345.54)	9261	
-3	(-66.26)	84.4		-3	(-518.32)	9290	
-4	(-88.34)	84.1		-4	(-691.09)	9319	
-5	(-110.43)	83.9		-5	(-863.86)	9348	
-6	(-132.51)	83.6		-6	(-1036.63)	9377	
-7	(-154.60)	83.4		-7	(-1209.41)	9406	
-8	(-176.68)	83.1		-8	(-1382.18)	9435	
-9	(-198.77)	82.9		-9	(-1554.95)	9464	
-10	(-220.85)	82.6		-10	(-1727.72)	9493	
	WEIGHTING FACTOR =	0.37			WEIGHTING FACTOR =	2.92	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	202.55	96.9		+10	1148.16	9284	
+9	182.29	96.7		+9	1033.34	9299	
+8	162.04	96.5		+8	918.53	9314	
+7	141.78	96.3		+7	803.71	9330	
+6	121.53	96.1		+6	688.89	9345	
+5	101.27	95.9		+5	574.08	9360	
+4	81.02	95.7		+4	459.26	9375	
+3	60.76	95.5		+3	344.45	9391	
+2	40.51	95.3		+2	229.63	9406	
+1	20.25	95.1		+1	114.82	9421	<- Adj. Act. HR=9424
					0.00	9437	
0	0.00	94.9		0	0.00	9512	
					(0.00)	9587	
-1	(-20.25)	94.7		-1	(-114.82)	9602	
-2	(-40.51)	94.5		-2	(-229.63)	9617	
-3	(-60.76)	94.3		-3	(-344.45)	9633	
-4	(-81.02)	94.1		-4	(-459.26)	9648	
-5	(-101.27)	93.9		-5	(-574.08)	9663	
-6	(-121.53)	93.7		-6	(-688.89)	9678	
-7	(-141.78)	93.5		-7	(-803.71)	9694	
-8	(-162.04)	93.3	<- Adj. Act. EAF= 93.3	-8	(-918.53)	9709	
-9	(-182.29)	93.1		-9	(-1033.34)	9724	
-10	(-202.55)	92.9		-10	(-1148.16)	9740	
	WEIGHTING FACTOR =	0.34			WEIGHTING FACTOR =	1.94	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,552.64	88.4		+10	2960.56	10860	
+9	4,997.37	88.1		+9	2664.50	10881	
+8	4,442.11	87.8	<- Adj. Act. EAF= 88.0	+8	2368.45	10902	
+7	3,886.85	87.5		+7	2072.39	10924	
+6	3,331.58	87.2		+6	1776.34	10945	
+5	2,776.32	86.9		+5	1480.28	10966	
+4	2,221.05	86.6		+4	1184.22	10988	
+3	1,665.79	86.3		+3	888.17	11009	
+2	1,110.53	86.0		+2	592.11	11031	
+1	555.26	85.7		+1	296.06	11052	
					0.00	11073	<- Adj. Act. HR=11084
0	0.00	85.4		0	0.00	11148	
					(0.00)	11223	
-1	(-555.26)	85.1		-1	(-373.71)	11245	
-2	(-1,110.53)	84.8		-2	(-747.42)	11266	
-3	(-1,665.79)	84.5		-3	(-1121.12)	11288	
-4	(-2,221.05)	84.2		-4	(-1494.83)	11309	
-5	(-2,776.32)	83.9		-5	(-1868.54)	11330	
-6	(-3,331.58)	83.6		-6	(-2242.25)	11352	
-7	(-3,886.85)	83.3		-7	(-2615.96)	11373	
-8	(-4,442.11)	83.0		-8	(-2989.66)	11394	
-9	(-4,997.37)	82.7		-9	(-3363.37)	11416	
-10	(-5,552.64)	82.4		-10	(-3737.08)	11437	
	WEIGHTING FACTOR =	9.38			WEIGHTING FACTOR =	5.00	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,568.74	88.4	<- Adj. Act. EAF= 91.8	+10	3167.72	10810	
+9	5,011.86	88.1		+9	2850.94	10834	
+8	4,454.99	87.8		+8	2534.17	10857	
+7	3,898.12	87.5		+7	2217.40	10880	
+6	3,341.24	87.2		+6	1900.63	10904	
+5	2,784.37	86.9		+5	1583.86	10927	
+4	2,227.49	86.6		+4	1267.09	10950	
+3	1,670.62	86.3		+3	950.31	10974	
+2	1,113.75	86.0		+2	633.54	10997	
+1	556.87	85.7		+1	316.77	11020	
					0.00	11044	
0	0.00	85.4		0	0.00	11119	<- Adj. Act. HR=11132
					(0.00)	11194	
-1	(-556.87)	85.1		-1	(-375.29)	11217	
-2	(-1,113.75)	84.8		-2	(-750.58)	11240	
-3	(-1,670.62)	84.5		-3	(-1125.86)	11264	
-4	(-2,227.49)	84.2		-4	(-1501.15)	11287	
-5	(-2,784.37)	83.9		-5	(-1876.44)	11310	
-6	(-3,341.24)	83.6		-6	(-2251.73)	11334	
-7	(-3,898.12)	83.3		-7	(-2627.01)	11357	
-8	(-4,454.99)	83.0		-8	(-3002.30)	11380	
-9	(-5,011.86)	82.7		-9	(-3377.59)	11403	
-10	(-5,568.74)	82.4		-10	(-3752.88)	11427	
	WEIGHTING FACTOR =	9.41			WEIGHTING FACTOR =	5.35	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	7,241.65	96.6	<- Adj. Act. EAF= 100.0	+10	1166.56	10694	
+9	6,517.48	96.3		+9	1049.90	10700	
+8	5,793.32	96.0		+8	933.25	10707	
+7	5,069.15	95.7		+7	816.59	10713	
+6	4,344.99	95.4		+6	699.94	10720	
+5	3,620.82	95.1		+5	583.28	10727	
+4	2,896.66	94.8		+4	466.62	10733	
+3	2,172.49	94.5		+3	349.97	10740	
+2	1,448.33	94.2		+2	233.31	10746	
+1	724.16	93.9		+1	116.66	10753	
					0.00	10759	<- Adj. Act. HR=10824
0	0.00	93.6		0	0.00	10834	
					(0.00)	10909	
-1	(-724.16)	93.3		-1	(-144.64)	10916	
-2	(-1,448.33)	93.0		-2	(-289.27)	10922	
-3	(-2,172.49)	92.7		-3	(-433.91)	10929	
-4	(-2,896.66)	92.4		-4	(-578.54)	10935	
-5	(-3,620.82)	92.1		-5	(-723.18)	10942	
-6	(-4,344.99)	91.8		-6	(-867.82)	10948	
-7	(-5,069.15)	91.5		-7	(-1012.45)	10955	
-8	(-5,793.32)	91.2		-8	(-1157.09)	10962	
-9	(-6,517.48)	90.9		-9	(-1301.72)	10968	
-10	(-7,241.65)	90.6		-10	(-1446.36)	10975	
	WEIGHTING FACTOR =	12.23			WEIGHTING FACTOR =	1.97	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,713.31	88.4		+10	1944.49	10650	
+9	5,141.98	88.1		+9	1750.04	10662	
+8	4,570.65	87.8		+8	1555.59	10673	
+7	3,999.32	87.5		+7	1361.14	10685	
+6	3,427.99	87.2		+6	1166.69	10697	
+5	2,856.65	86.9		+5	972.24	10709	
+4	2,285.32	86.6		+4	777.79	10721	
+3	1,713.99	86.3		+3	583.35	10733	
+2	1,142.66	86.0		+2	388.90	10744	
+1	571.33	85.7		+1	194.45	10756	
					0.00	10768	
0	0.00	85.4	<- Adj. Act. EAF= 85.6	0	0.00	10843	<- Adj. Act. HR=10678
					(0.00)	10918	
-1	(-571.33)	85.1		-1	(-231.60)	10930	
-2	(-1,142.66)	84.8		-2	(-463.19)	10942	
-3	(-1,713.99)	84.5		-3	(-694.79)	10954	
-4	(-2,285.32)	84.2		-4	(-926.38)	10965	
-5	(-2,856.65)	83.9		-5	(-1157.98)	10977	
-6	(-3,427.99)	83.6		-6	(-1389.57)	10989	
-7	(-3,999.32)	83.3		-7	(-1621.17)	11001	
-8	(-4,570.65)	83.0		-8	(-1852.76)	11013	
-9	(-5,141.98)	82.7		-9	(-2084.36)	11025	
-10	(-5,713.31)	82.4		-10	(-2315.96)	11037	
	WEIGHTING FACTOR =	9.65			WEIGHTING FACTOR =	3.28	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	2,268.31	96.1		+10	1773.03	9724	
+9	2,041.48	95.9		+9	1595.73	9743	
+8	1,814.65	95.6		+8	1418.43	9762	
+7	1,587.82	95.4		+7	1241.12	9782	
+6	1,360.99	95.1		+6	1063.82	9801	
+5	1,134.15	94.9		+5	886.52	9820	
+4	907.32	94.6		+4	709.21	9840	
+3	680.49	94.4		+3	531.91	9859	
+2	453.66	94.1		+2	354.61	9878	
+1	226.83	93.9	<- Adj. Act. EAF= 93.9	+1	177.30	9897	
					0.00	9917	<- Adj. Act. HR=9958
0	0.00	93.6		0	0.00	9992	
					(0.00)	10067	
-1	(-226.83)	93.4		-1	(-177.30)	10086	
-2	(-453.66)	93.1		-2	(-354.61)	10105	
-3	(-680.49)	92.9		-3	(-531.91)	10125	
-4	(-907.32)	92.6		-4	(-709.21)	10144	
-5	(-1,134.15)	92.4		-5	(-886.52)	10163	
-6	(-1,360.99)	92.1		-6	(-1063.82)	10182	
-7	(-1,587.82)	91.9		-7	(-1241.12)	10202	
-8	(-1,814.65)	91.6		-8	(-1418.43)	10221	
-9	(-2,041.48)	91.4		-9	(-1595.73)	10240	
-10	(-2,268.31)	91.1		-10	(-1773.03)	10260	
	WEIGHTING FACTOR =	3.83			WEIGHTING FACTOR =	2.99	

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2003

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Cape Canaveral 2	11/29/2003 - 12/24/2003	Turbine valves and boiler
Lauderdale 4	04/04/2003 - 04/28/2003	4A CT rotor change out
Lauderdale 5	10/26/2003 - 11/07/2003	Overhaul
Manatee 2	NONE	
Martin 1	4/14/03 - 5/2/03 and 11/2/03 - 11/23/03	Overhaul
Martin 2	11/24/2003 - 12/19/2003	Overhaul
Martin 3	02/16/2003 - 02/22/2003	3A CT overhaul
Martin 4	10/30/2003 - 12/16/2003	4B CT rotor change out
Turkey Point 1	02/14/2003 - 04/20/2003	Turbine generator
Turkey Point 2	NONE	
Turkey Point 3	03/01/2003 - 03/28/2003	Refueling
Turkey Point 4	10/01/2003 - 11/05/2003	Refueling
St. Lucie 1	NONE	
St. Lucie 2	04/20/2003 - 06/11/2003	Refueling
Scherer 4	NONE	

DOCUMENT NO. 1

WITNESS: PAMELA SONNELITTER

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 12
COMPANY/ FP+L
WITNESS: P. Sonnelitter (PS-2)
DATE: 11-08-04

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2005

DOCUMENT	PAGE NUMBER	TITLE
1	7.201.001	Index
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 - 7.201.023	Unit MOF and FOF vs Time Graphs
	7.201.024	Planned Outages Schedule (Estimated)

Table 2.0
POWRSYM Projected System Generation
January Through December, 2005

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Ft. Myers Repowered 2	1,435	7,833	10,267,693	91%	10.9	10.9	510,893
Sanford Repowered 4	911	7,654	6,445,312	92%	6.8	17.7	320,981
Sanford Repowered 5	939	7,601	6,257,420	88%	6.6	24.3	310,015
St. Lucie 2	719	8,538	6,140,275	100%	6.5	30.8	20,538
St. Lucie 1	845	7,135	6,027,256	100%	6.4	37.2	18,908
Turkey Point 3	703	8,538	6,003,740	100%	6.4	43.6	22,258
Turkey Point 4	703	7,017	4,949,673	100%	5.2	48.8	17,484
Scherer 4	645	7,844	4,536,350	90%	4.8	53.6	69,980
Martin 8	1,088	4,681	4,178,436	82%	4.4	58.1	200,600
Manatee 3	1,090	4,685	4,158,969	81%	4.4	62.5	209,570
Martin 2	799	6,542	3,530,341	68%	3.7	66.2	217,479
Lauderdale 4	433	8,003	3,278,217	95%	3.5	69.7	180,355
Martin 4	453	7,662	3,112,541	90%	3.3	73.0	155,280
Martin 3	452	7,679	3,092,943	89%	3.3	76.3	158,574
Martin 1	807	5,534	2,934,991	66%	3.1	79.4	183,791
Manatee 2	806	5,268	2,625,941	62%	2.8	82.1	142,807
Lauderdale 5	432	6,595	2,622,653	92%	2.8	84.9	143,207
Manatee 1	806	4,501	2,366,608	65%	2.5	87.4	124,976
Cape Canaveral 2	396	3,464	1,131,851	83%	1.2	88.6	57,557
Port Everglades 4	389	3,665	1,125,166	79%	1.2	89.8	59,426
Turkey Point 1	395	3,485	1,078,681	78%	1.1	91.0	55,473
Port Everglades 3	382	3,564	1,076,572	79%	1.1	92.1	55,707
St. Johns River 2	128	7,854	1,001,597	99%	1.1	93.2	14,939
Cape Canaveral 1	396	3,069	978,300	81%	1.0	94.2	51,244
Riviera 4	280	4,309	953,477	79%	1.0	95.2	52,414
Riviera 3	274	4,445	942,814	77%	1.0	96.2	52,047
St. Johns River 1	128	6,478	824,409	99%	0.9	97.1	12,481
Turkey Point 2	395	2,583	755,734	74%	0.8	97.9	40,503
Ft. Myers SC 3	165	1,540	428,733	84%	0.5	98.3	33,129
Putnam 1	244	2,193	374,086	70%	0.4	98.7	23,817
Putnam 2	244	1,845	299,178	67%	0.3	99.0	19,966
Port Everglades 2	210	1,503	188,394	60%	0.2	99.2	11,481
Port Everglades 1	210	1,398	162,015	55%	0.2	99.4	10,756
Sanford 3	139	1,687	143,226	61%	0.2	99.6	8,171
Ft. Myers GT 1-12	582	425	128,859	52%	0.1	99.7	17,754
Ft. lauderdale GT 1-24	719	395	90,008	32%	0.1	99.8	11,810
Port Everglades GT 1-1:	363	385	82,248	59%	0.1	99.9	10,601
Cutler 6	140	1,125	69,916	44%	0.1	100.0	6,106
Cutler 5	69	1,085	33,836	45%	0.0	100.0	3,055
Total	20,311		94,398,455		100.0	100.0	3,616,135

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2005

Lauderdale Unit 4

Lauderdale Unit 5

Manatee Unit 1

Manatee Unit 2

Martin Unit 1

Martin Unit 2

Martin Unit 3

Martin Unit 4

Scherer Unit 4

St. Lucie Unit 1

St. Lucie Unit 2

Turkey Point Unit 3

Turkey Point Unit 4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2005

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	71,721	25,569
+ 9	64,549	23,012
+ 8	57,377	20,455
+ 7	50,205	17,898
+ 6	43,033	15,342
+ 5	35,861	12,785
+ 4	28,689	10,228
+ 3	21,516	7,671
+ 2	14,344	5,114
+ 1	7,172	2,557
0	0	0
- 1	(7,175)	(2,557)
- 2	(14,350)	(5,114)
- 3	(21,525)	(7,671)
- 4	(28,700)	(10,228)
- 5	(35,875)	(12,785)
- 6	(43,050)	(15,342)
- 7	(50,225)	(17,898)
- 8	(57,400)	(20,455)
- 9	(64,576)	(23,012)
- 10	(71,751)	(25,569)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	6,029,044,746
LINE 2	MONTH OF JANUARY	2005	$	6,158,490,202
LINE 3	MONTH OF FEBRUARY	2005	$	6,143,724,921
LINE 4	MONTH OF MARCH	2005	$	6,154,980,006
LINE 5	MONTH OF APRIL	2005	$	6,163,547,843
LINE 6	MONTH OF MAY	2005	$	6,179,880,106
LINE 7	MONTH OF JUNE	2005	$	6,197,832,313
LINE 8	MONTH OF JULY	2005	$	6,423,964,998
LINE 9	MONTH OF AUGUST	2005	$	6,430,544,904
LINE 10	MONTH OF SEPTEMBER	2005	$	6,423,676,130
LINE 11	MONTH OF OCTOBER	2005	$	6,398,663,851
LINE 12	MONTH OF NOVEMBER	2005	$	6,380,648,929
LINE 13	MONTH OF DECEMBER	2005	$	6,525,480,148
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	6,277,729,000
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	25,958,449
LINE 18	JURISDICTIONAL SALES			103,009,995,124 KWH
LINE 19	TOTAL SALES			104,577,999,841 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.50%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	25,569,237

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Lauderdale 4	0.71	92.7	94.7	90.7	509.0	-509.0
Lauderdale 5	0.48	75.5	77.5	73.5	344.6	-344.6
Manatee 1	0.45	74.6	76.6	72.6	320.1	-320.1
Manatee 2	0.51	96.0	98.0	94.0	368.7	-368.7
Martin 1	0.44	76.0	78.5	73.5	318.1	-318.1
Martin 2	0.35	92.9	95.4	90.4	254.2	-254.2
Martin 3	1.20	92.2	95.2	89.2	859.7	-859.7
Martin 4	1.10	92.5	95.0	90.0	785.8	-785.8
Scherer 4	4.89	95.5	97.5	93.5	3,503.7	-3,503.7
St. Lucie 1	12.44	77.2	80.2	74.2	8,919.5	-8,919.5
St. Lucie 2	12.79	93.6	96.6	90.6	9,173.4	-9,173.4
Turkey Point 3	12.43	93.6	96.6	90.6	8,913.0	-8,913.0
Turkey Point 4	10.45	75.8	78.8	72.8	7,492.8	-7,492.8
	58.23				41,762.8	-41,762.8

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Lauderdale 4	7.63	7,515	94.7	7,212	7,818	5,474.0	-5,474.0
Lauderdale 5	1.74	7,511	92.2	7,371	7,651	1,246.7	-1,246.7
Manatee 1	2.98	10,274	65.2	10,023	10,524	2,134.2	-2,134.2
Manatee 2	5.12	10,248	61.9	9,910	10,587	3,672.5	-3,672.5
Martin 1	3.62	9,994	65.7	9,778	10,210	2,596.0	-2,596.0
Martin 2	4.36	9,964	67.5	9,746	10,183	3,129.8	-3,129.8
Martin 3	1.68	6,977	89.1	6,849	7,105	1,206.0	-1,206.0
Martin 4	3.14	6,926	89.8	6,750	7,101	2,254.7	-2,254.7
Scherer 4	1.07	10,151	89.7	9,965	10,336	765.0	-765.0
St. Lucie 1	0.77	10,846	100.0	10,793	10,899	550.3	-552.6
St. Lucie 2	0.04	10,866	100.0	10,790	10,942	25.2	-25.3
Turkey Point 3	5.93	11,043	100.0	10,787	11,299	4,253.4	-4,268.8
Turkey Point 4	3.70	11,078	100.3	10,868	11,287	2,650.8	-2,662.3
	41.77					29,958.6	-29,987.8

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Lauderdale 4	7,515	94.7	433	8573	-11.17	303	07-01	06-04	Mar-04, Apr-04
Lauderdale 5	7,511	92.2	432	8131	-6.73	140	07-01	06-04	Nov-03, Dec-03, Jan-04
Manatee 1	10,274	65.2	806	10648	-5.73	250	07-01	06-04	Nov-02, Apr-03, May-03
Manatee 2	10,248	61.9	806	10822	-9.27	339	07-01	06-04	Nov-01, Feb-04, Mar-04, Apr-04
Martin 1	9,994	65.7	807	10189	-2.97	216	07-01	06-04	Oct-02, Feb-03
Martin 2	9,964	67.5	799	10234	-3.99	218	07-01	06-04	Nov-02, Jan-03, Feb-04, May-04
Martin 3	6,977	89.1	452	7336	-4.03	128	07-01	06-04	Aug-03, Sep-03
Martin 4	6,926	89.8	453	7145	-2.44	176	07-01	06-04	Jun-02, Jul-02, Nov-02, Nov-03
Scherer 4	10,151	89.7	645	10878	-8.12	186	07-01	06-04	No exclusions
St. Lucie 1	10,846	100.0	845	15106	-42.61	53	07-01	06-04	Oct-02, Apr-04
St. Lucie 2	10,866	100.0	719	13016	-21.50	76	07-01	06-04	Dec-01, Apr-03, May-03, Jun-03
Turkey Point 3	11,043	100.0	703	13204	-21.60	256	07-01	06-04	Oct-01, Mar-03
Turkey Point 4	11,078	100.3	703	14739	-36.48	210	07-01	06-04	Jul-02, Jan-03, Oct-03

DERIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Lauderdale 4	EAF	3,616,135	3,615,626	509.0	0.71
Lauderdale 4	ANOHR	3,616,135	3,610,661	5,474.0	7.63
Lauderdale 5	EAF	3,616,135	3,615,790	344.6	0.48
Lauderdale 5	ANOHR	3,616,135	3,614,888	1,246.7	1.74
Manatee 1	EAF	3,616,135	3,615,815	320.1	0.45
Manatee 1	ANOHR	3,616,135	3,614,001	2,134.2	2.98
Manatee 2	EAF	3,616,135	3,615,766	368.7	0.51
Manatee 2	ANOHR	3,616,135	3,612,463	3,672.5	5.12
Martin 1	EAF	3,616,135	3,615,817	318.1	0.44
Martin 1	ANOHR	3,616,135	3,613,539	2,596.0	3.62
Martin 2	EAF	3,616,135	3,615,881	254.2	0.35
Martin 2	ANOHR	3,616,135	3,613,005	3,129.8	4.36
Martin 3	EAF	3,616,135	3,615,275	859.7	1.20
Martin 3	ANOHR	3,616,135	3,614,929	1,206.0	1.68
Martin 4	EAF	3,616,135	3,615,349	785.8	1.10
Martin 4	ANOHR	3,616,135	3,613,880	2,254.7	3.14
Scherer 4	EAF	3,616,135	3,612,631	3,503.7	4.89
Scherer 4	ANOHR	3,616,135	3,615,370	765.0	1.07
St. Lucie 1	EAF	3,616,135	3,607,215	8,919.5	12.44
St. Lucie 1	ANOHR	3,616,135	3,615,585	550.3	0.77
St. Lucie 2	EAF	3,616,135	3,606,962	9,173.4	12.79
St. Lucie 2	ANOHR	3,616,135	3,616,110	25.2	0.04
Turkey Point 3	EAF	3,616,135	3,607,222	8,913.0	12.43
Turkey Point 3	ANOHR	3,616,135	3,611,882	4,253.4	5.93
Turkey Point 4	EAF	3,616,135	3,608,642	7,492.8	10.45
Turkey Point 4	ANOHR	3,616,135	3,613,484	2,650.8	3.70
	TOTAL			71,721.4	100.00

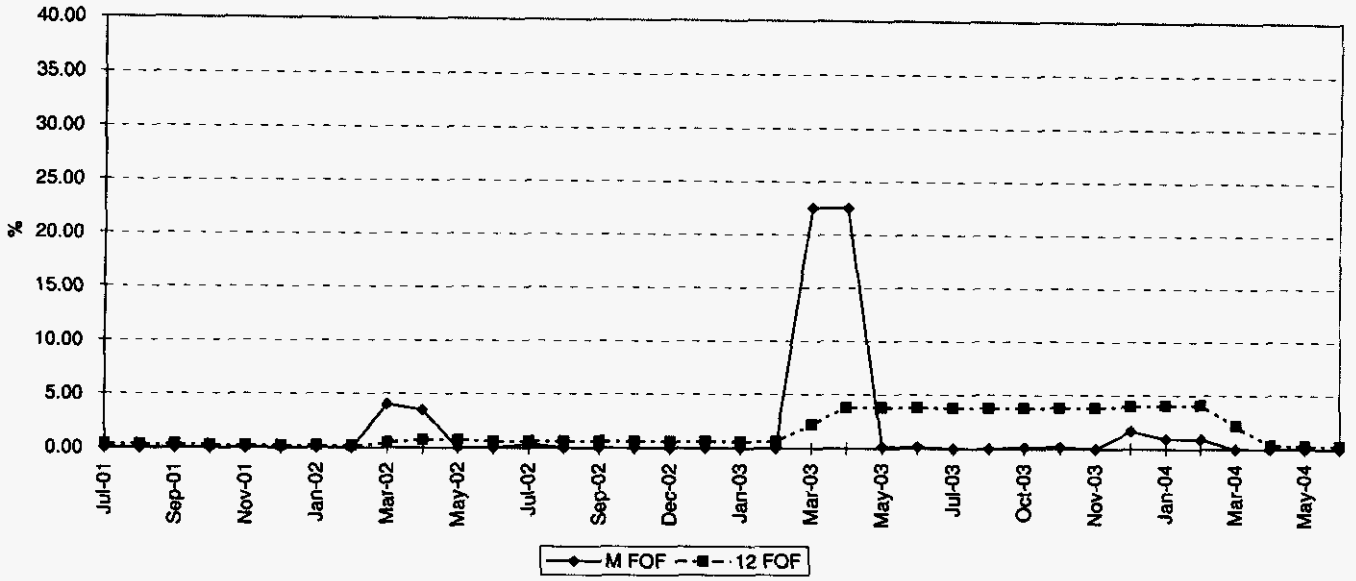
(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

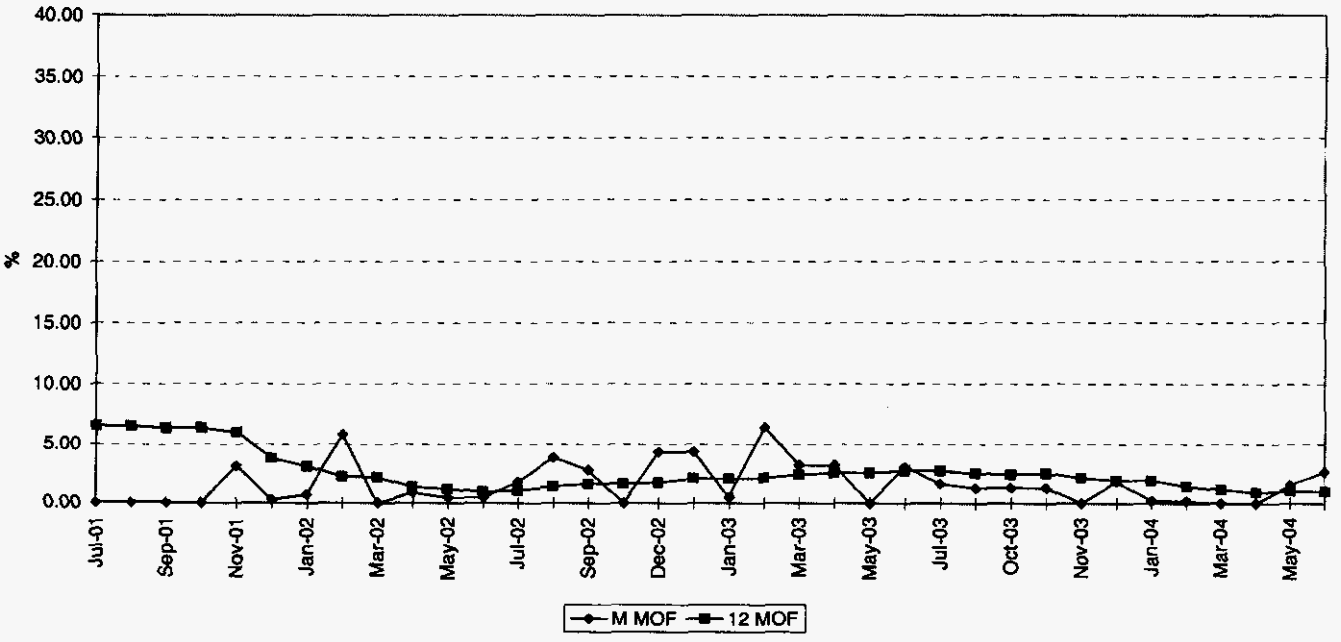
Plant/Unit	EAF	EPOF	EUOF	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET_GEN
Lauderdale 4	92.7	3.3	4.0	8760	8003	118	639	289	175	175	3,278,217
Lauderdale 5	75.5	19.7	4.8	8760	6595	19	2146	1726	175	245	2,622,653
Manatee 1	74.6	20.5	4.9	8760	4501	2034	2225	1796	254	175	2,366,608
Manatee 2	96.0	0.0	4.0	8760	5268	3142	350	0	175	175	2,625,941
Martin 1	76.0	17.3	6.7	8760	5534	1124	2102	1515	412	175	2,934,991
Martin 2	92.9	0.0	7.1	8760	6542	1596	622	0	175	447	3,530,341
Martin 3	92.2	0.8	7.0	8760	7679	398	683	70	263	350	3,092,943
Martin 4	92.5	2.5	5.0	8760	7662	441	657	219	175	263	3,112,541
Scherer 4	95.5	0.0	4.5	8760	7844	522	394	0	175	219	4,536,350
St. Lucie 1	77.2	16.4	6.4	8760	6759	0	2001	1440	280	280	6,027,256
St. Lucie 2	93.6	0.0	6.4	8760	8199	0	561	0	280	280	6,140,275
Turkey Point 3	93.6	0.0	6.4	8760	8199	0	561	0	280	280	6,003,740
Turkey Point 4	75.8	17.8	6.4	8760	6639	0	2121	1560	280	280	4,949,673

EPOF = equivalent planned outage factor. EPOF=(EPOH/PH)*100
EUOF = equivalent unavailable outage factor. EUOF=((EFOH+EMOH)/PH)*100
PH = period hours
SH = service hours
RSH = reserve shutdown
UH = unavailable hours . UH=PH-SH-RSH
EPOH = equivalent planned outage hours
EFOH = equivalent forced outage hours
EMOH = equivalent maintenance outage hours

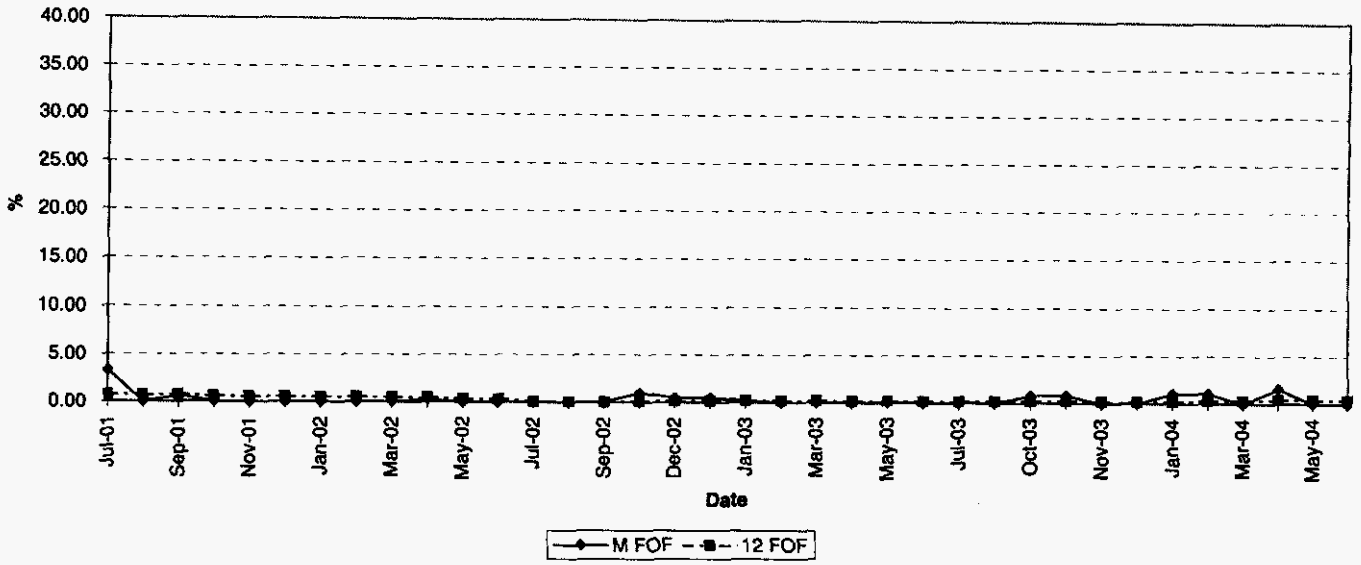
PFL 4
FORCED OUTAGE FACTOR



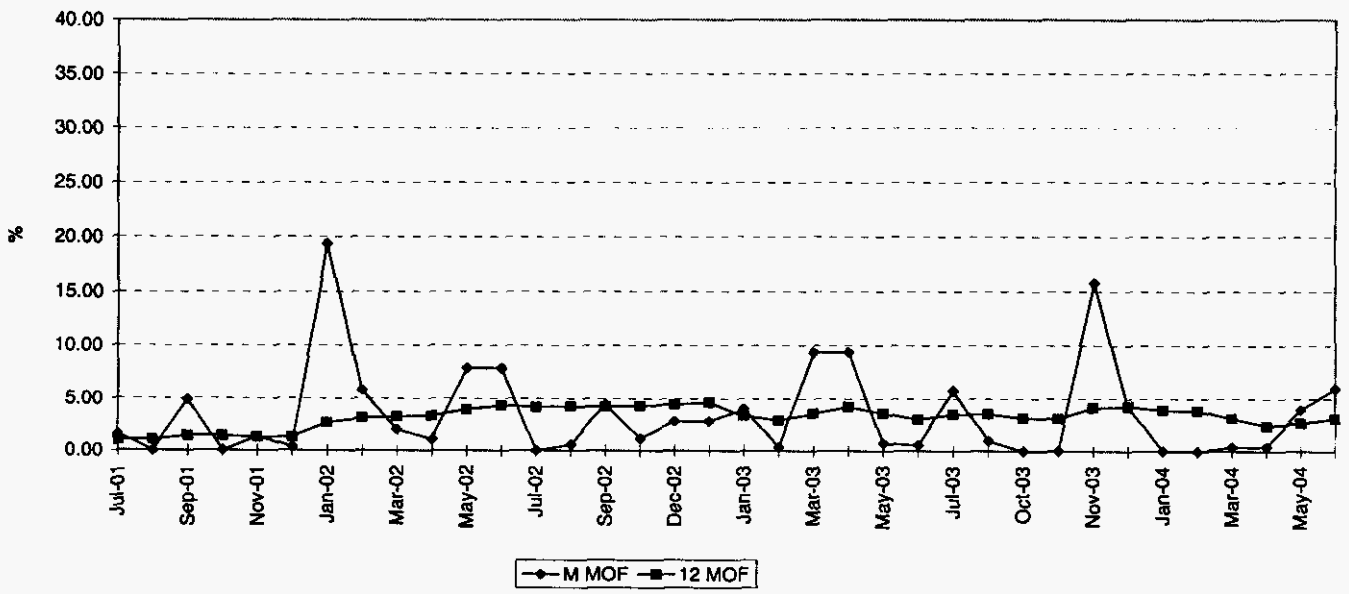
MAINTENANCE OUTAGE FACTOR



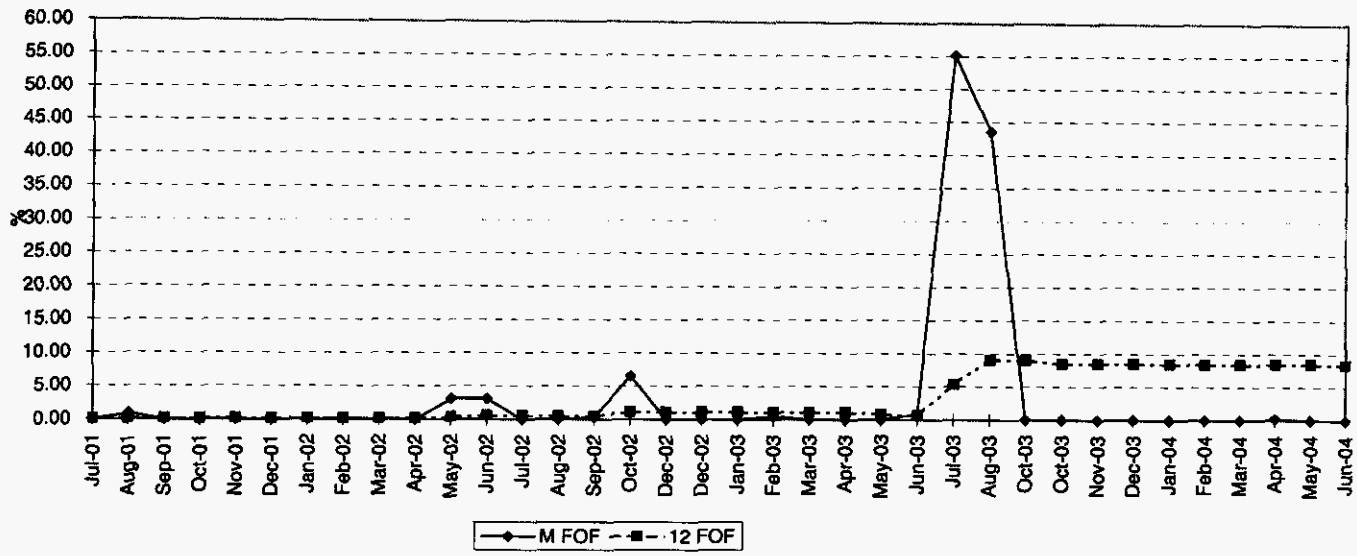
PFL 5
FORCED OUTAGE FACTOR



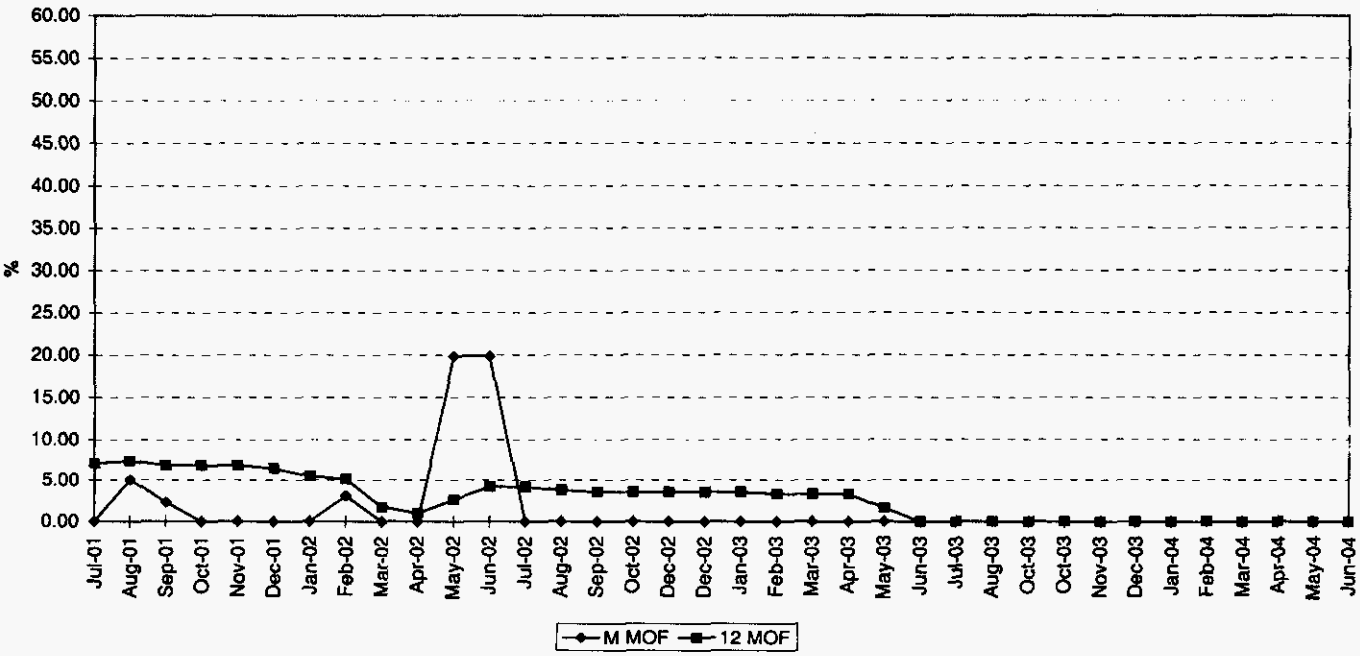
MAINTENANCE OUTAGE FACTOR



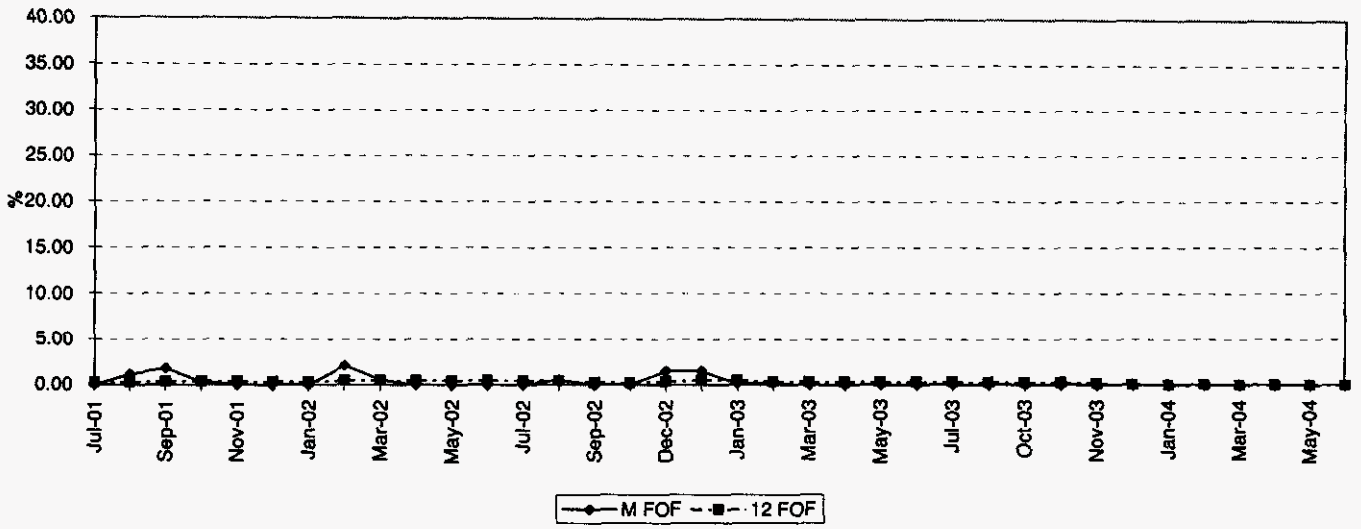
PMT 1
FORCED OUTAGE FACTOR



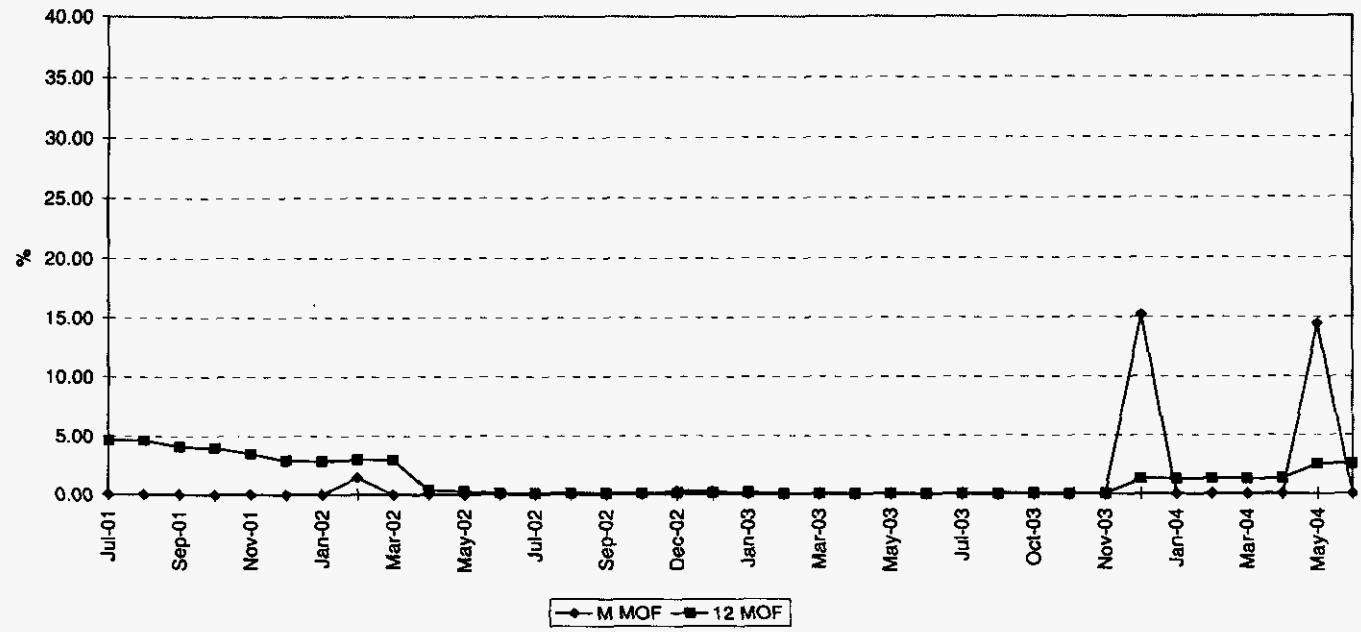
MAINTENANCE OUTAGE FACTOR



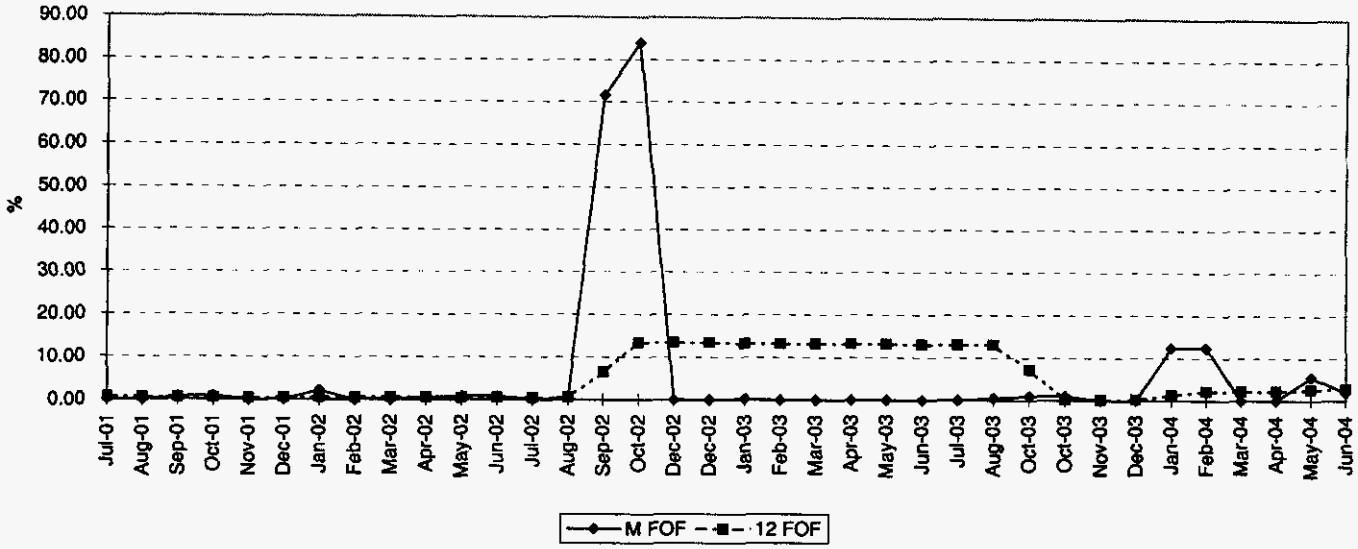
PMT 2
FORCED OUTAGE FACTOR



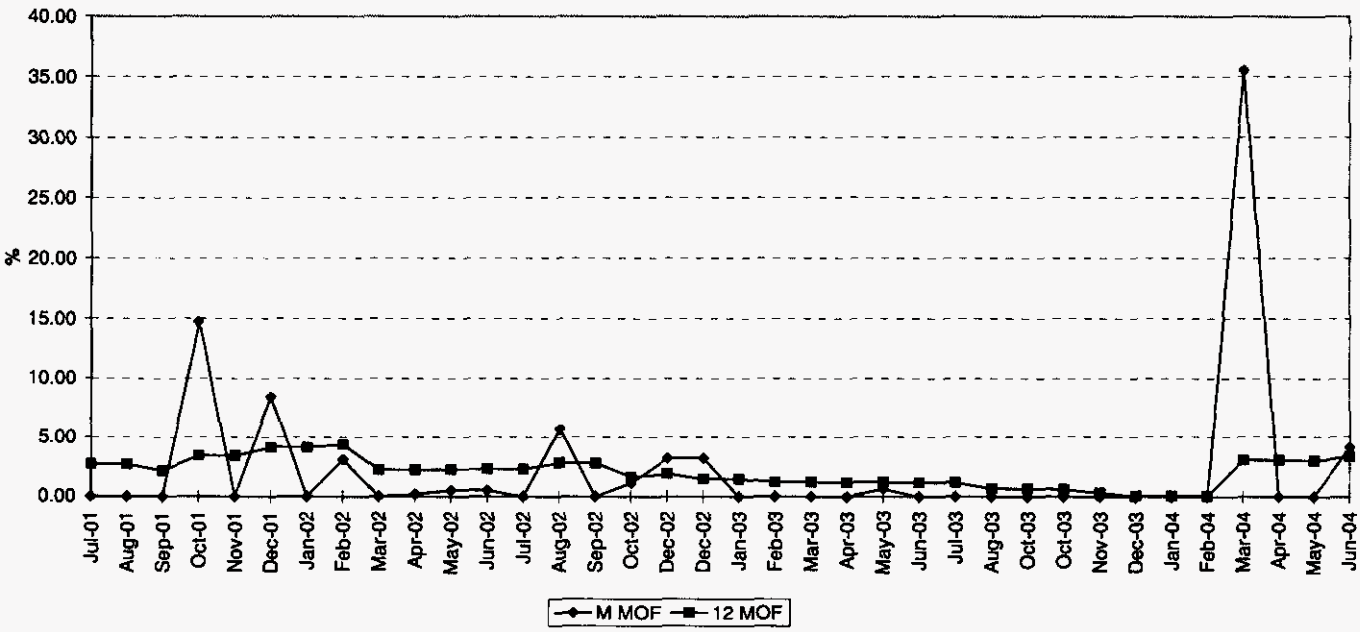
MAINTENANCE OUTAGE FACTOR



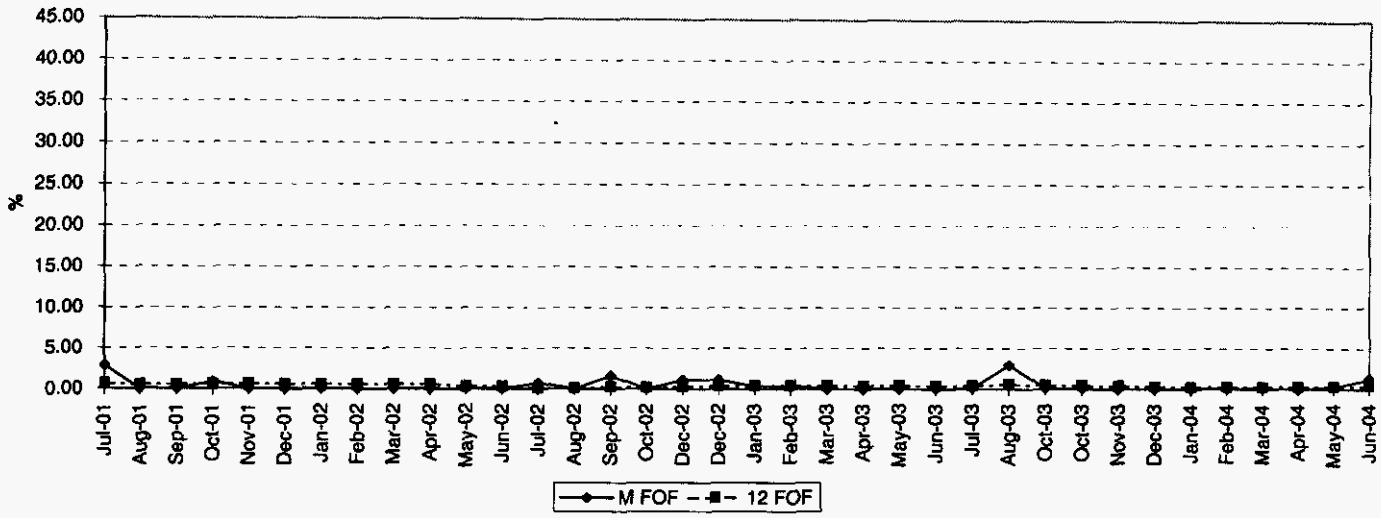
PMR 1
FORCED OUTAGE FACTOR



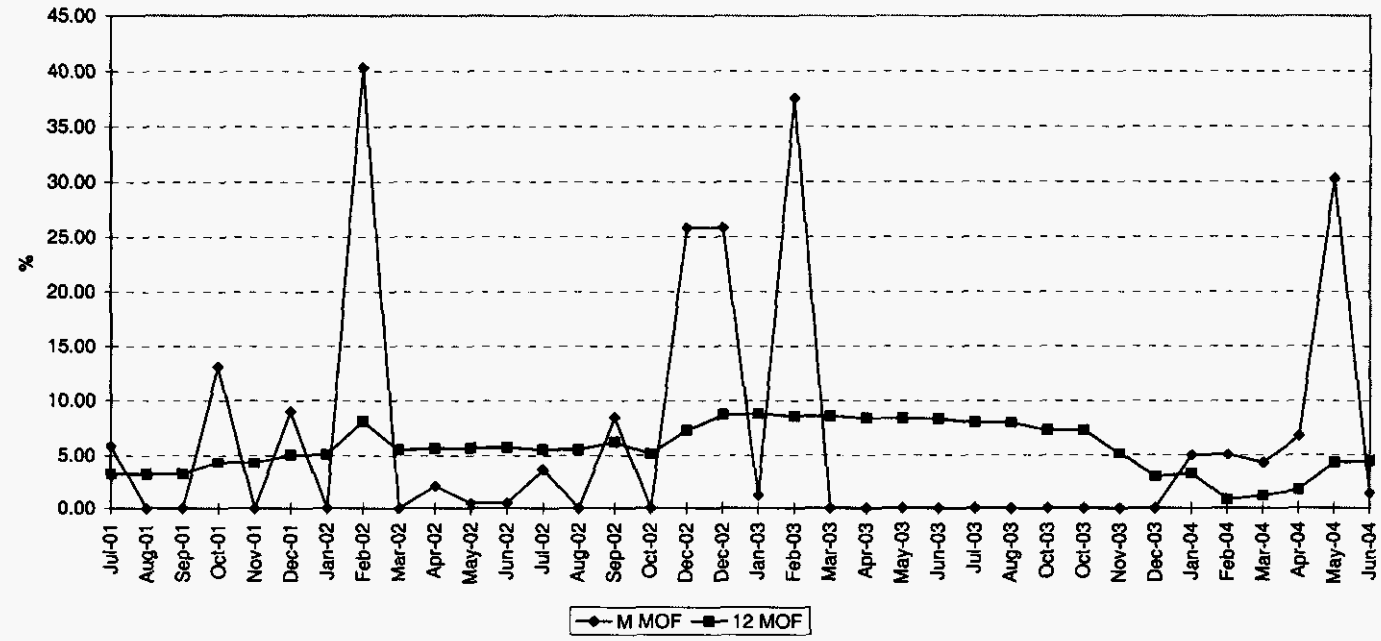
MAINTENANCE OUTAGE FACTOR



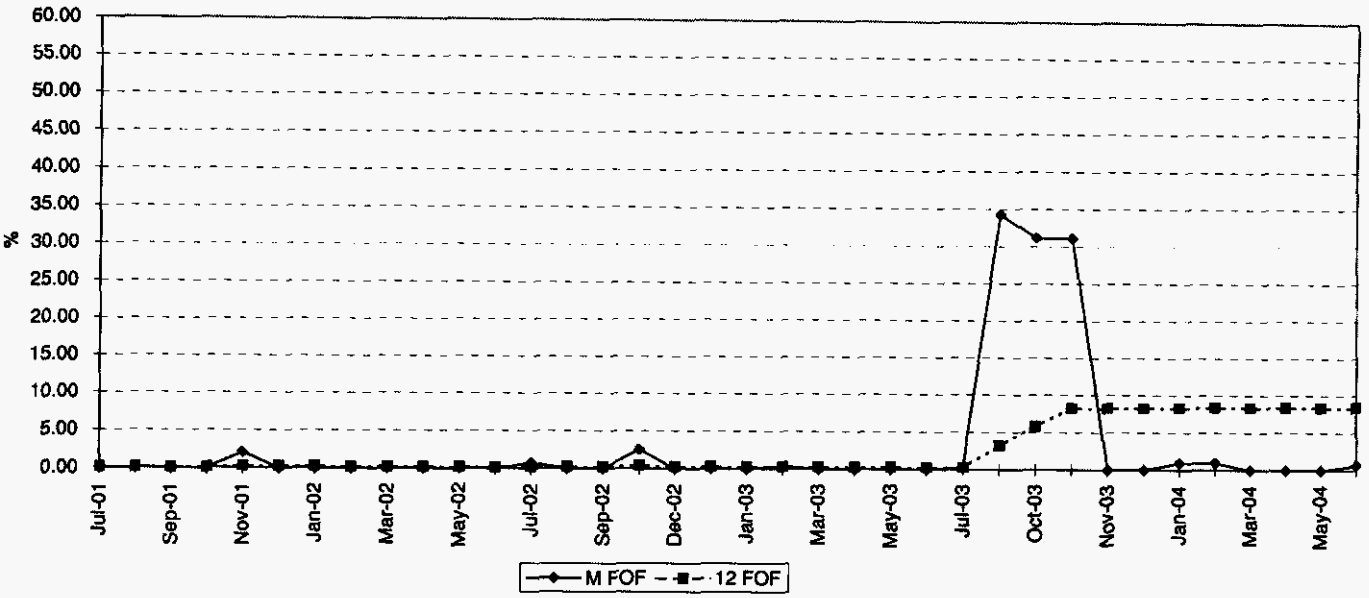
PMR 2
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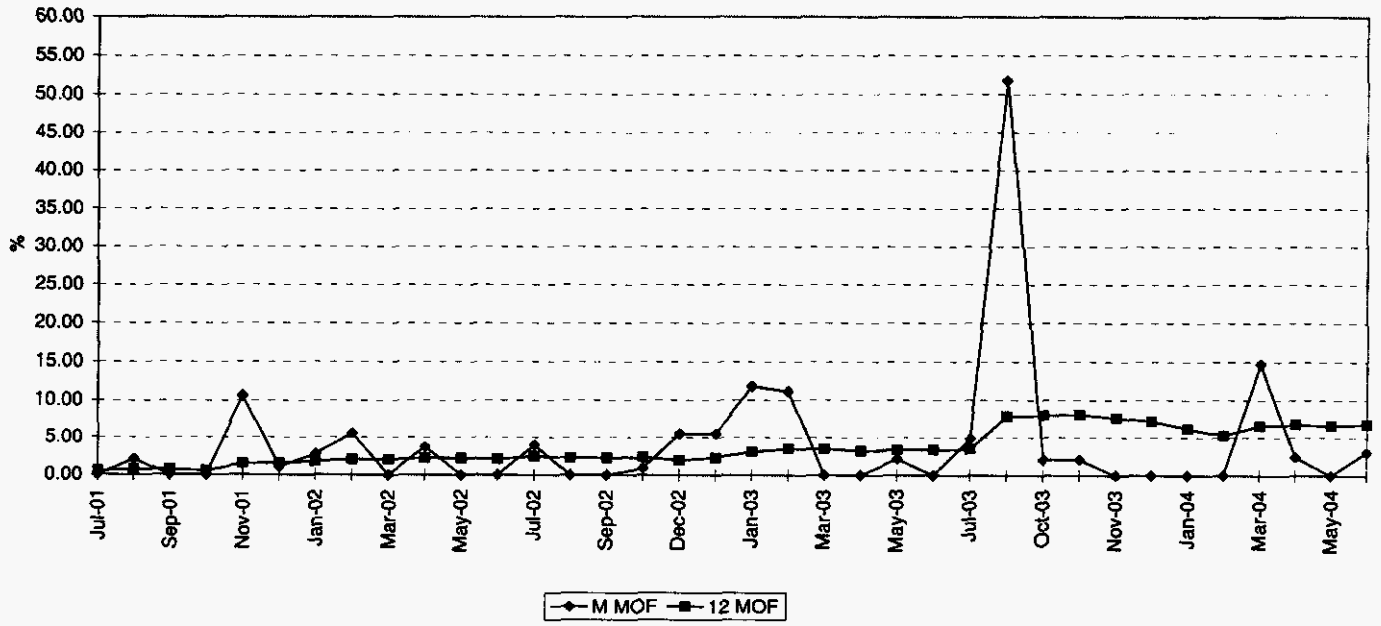
MAINTENANCE OUTAGE FACTOR



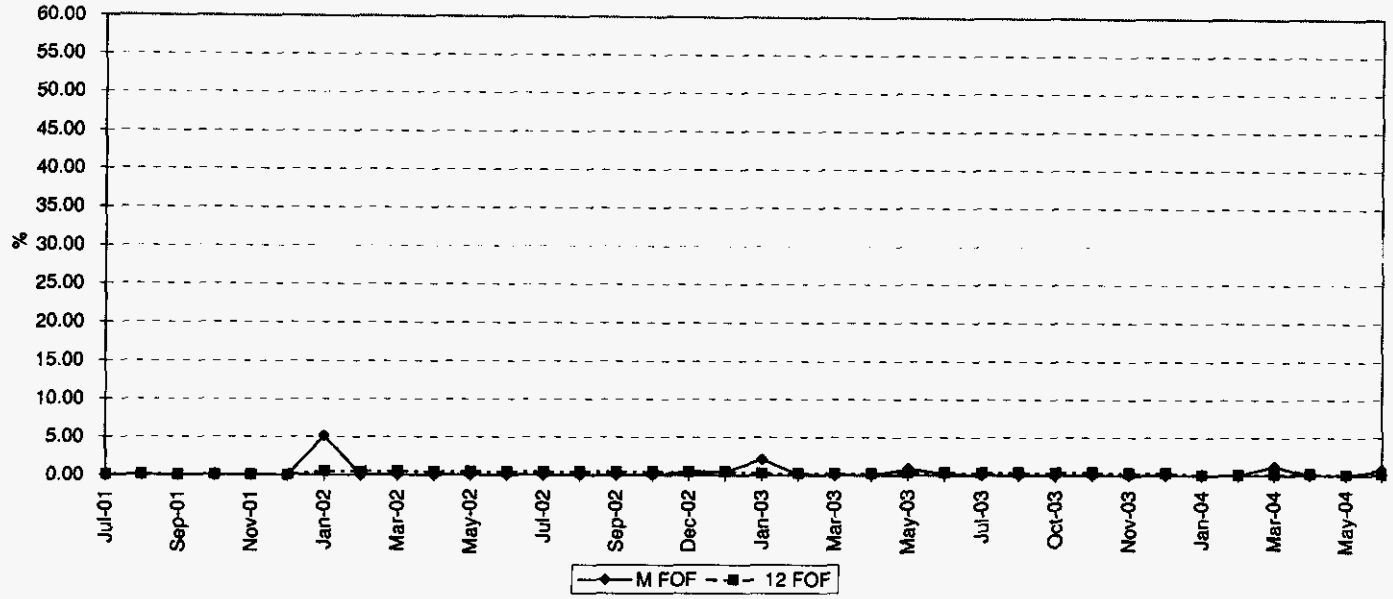
PMG 3
FORCED OUTAGE FACTOR



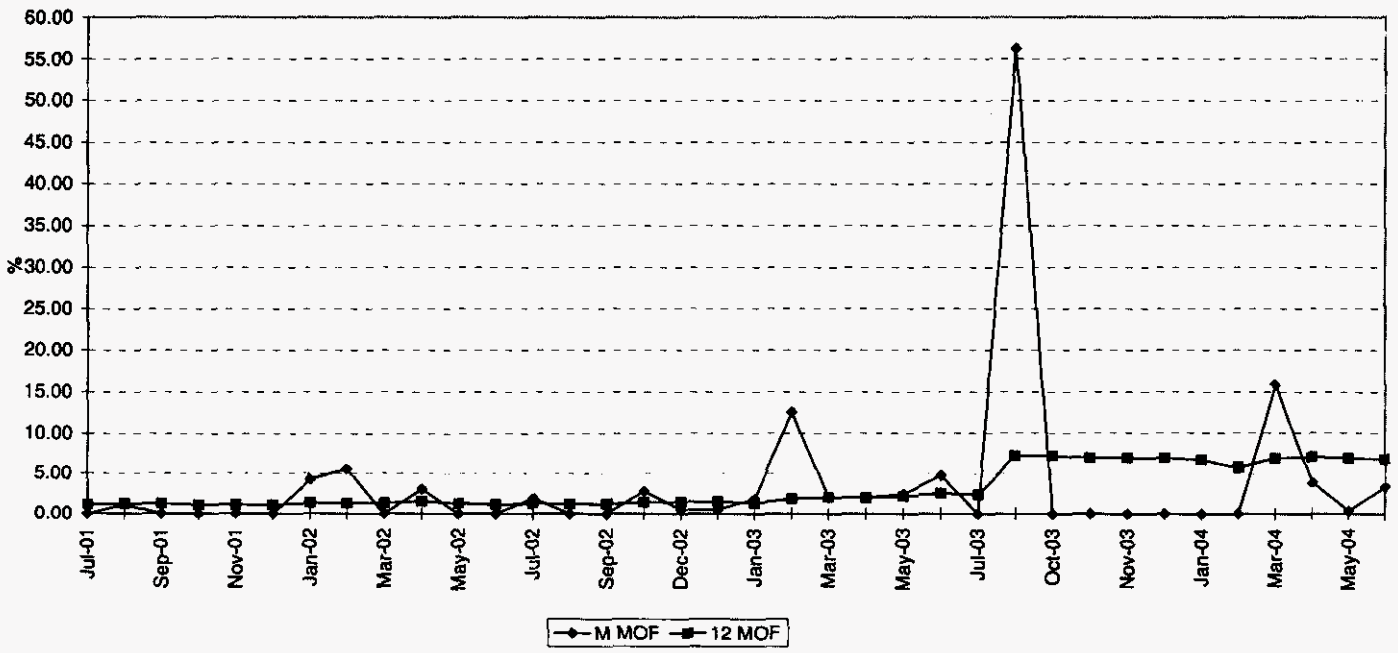
MAINTENANCE OUTAGE FACTOR



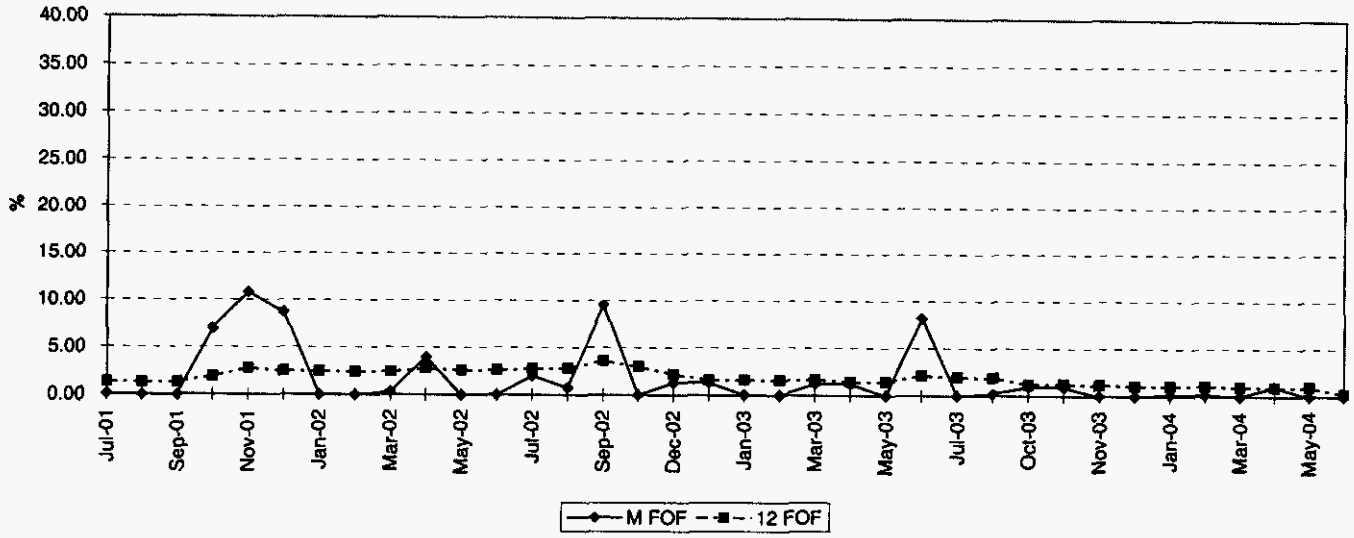
PMG 4
FORCED OUTAGE FACTOR



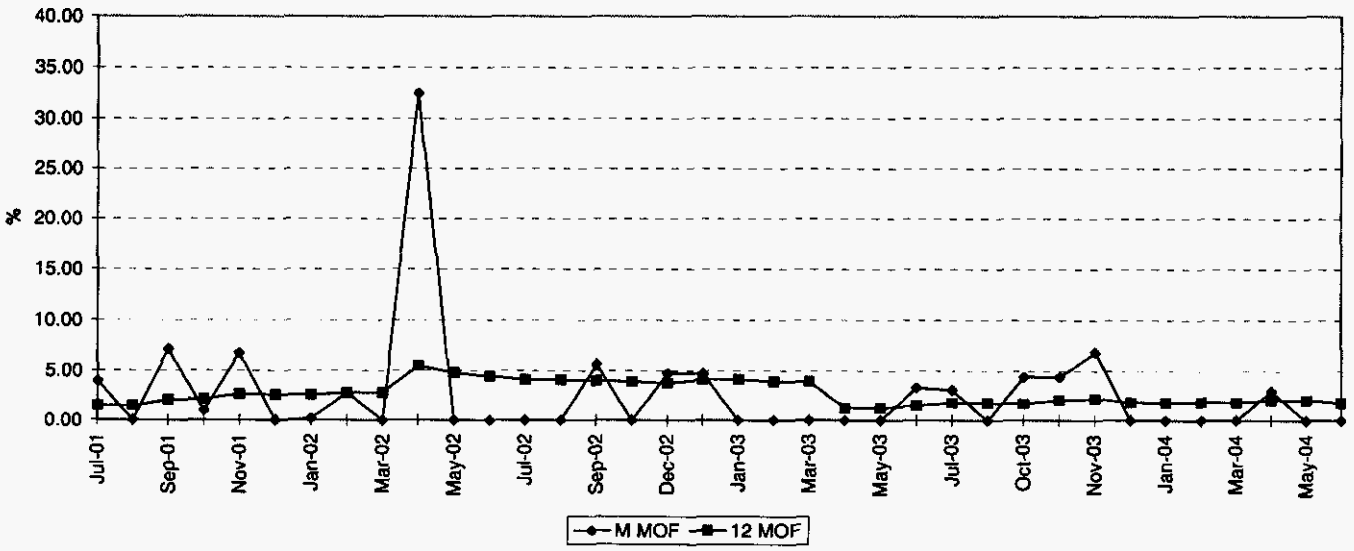
MAINTENANCE OUTAGE FACTOR



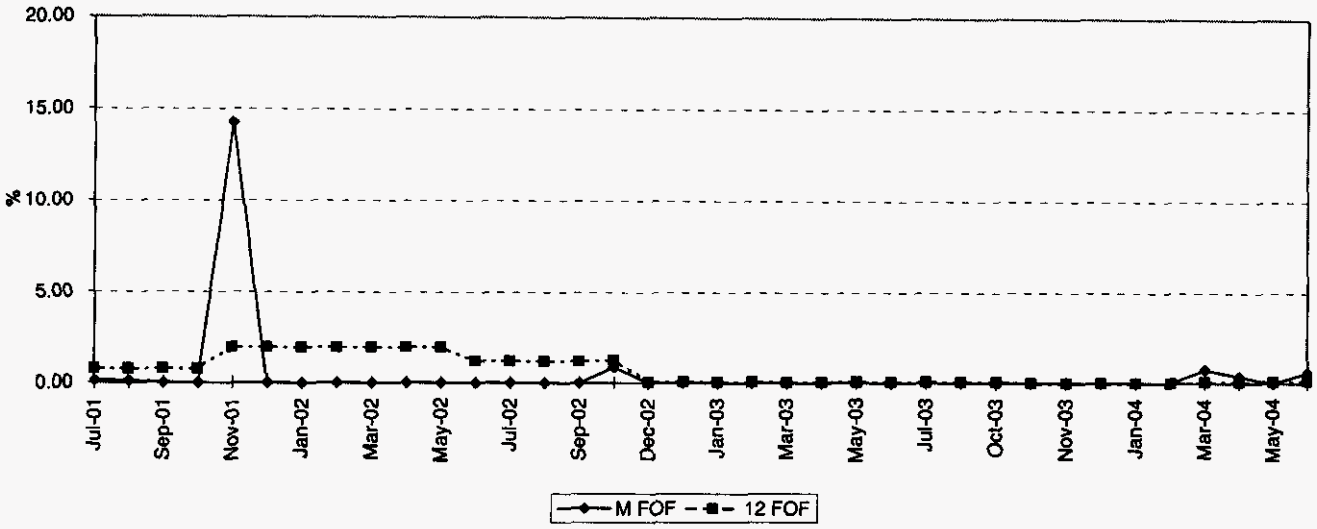
PSG 4
FORCED OUTAGE FACTOR



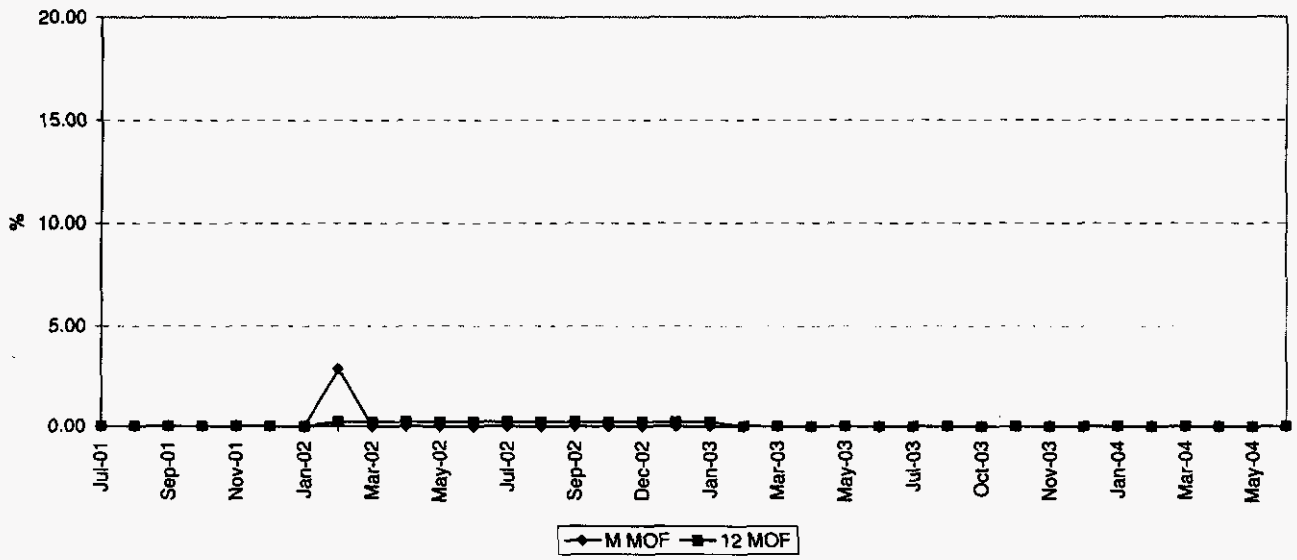
MAINTENANCE OUTAGE FACTOR



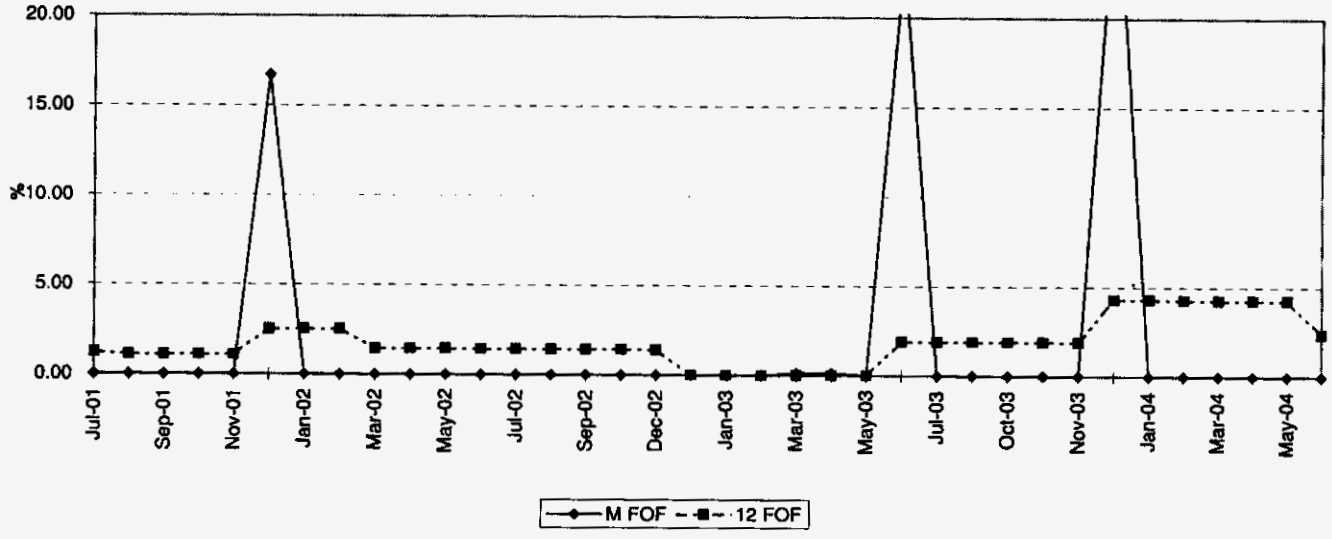
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FORCED OUTAGE FACTOR



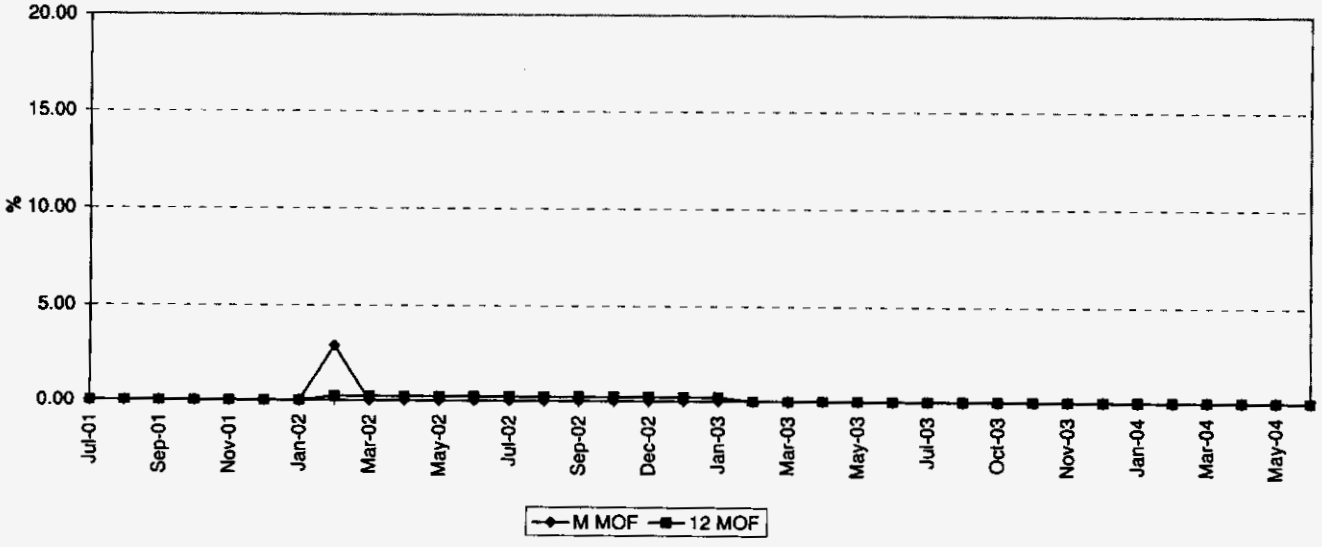
MAINTENANCE OUTAGE FACTOR



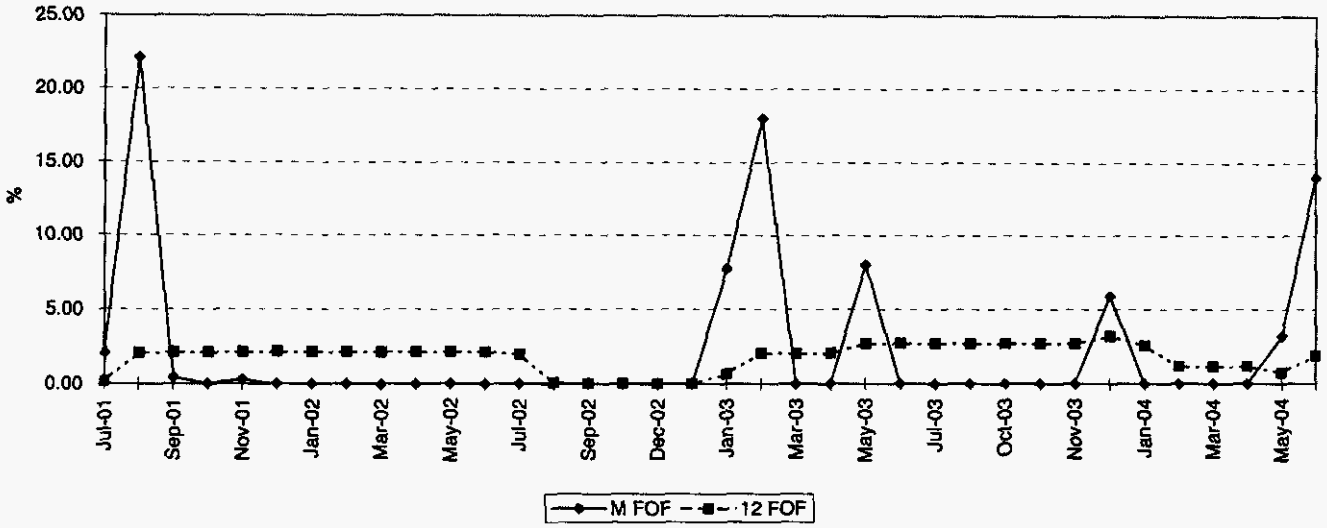
PSL 2
FORCED OUTAGE FACTOR



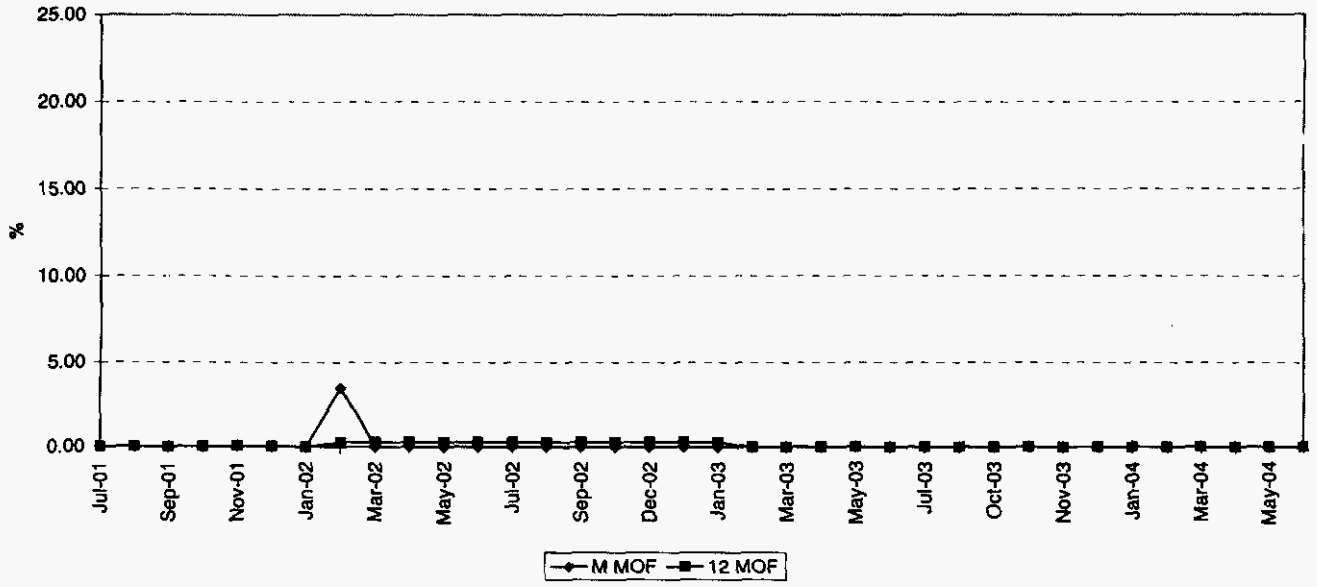
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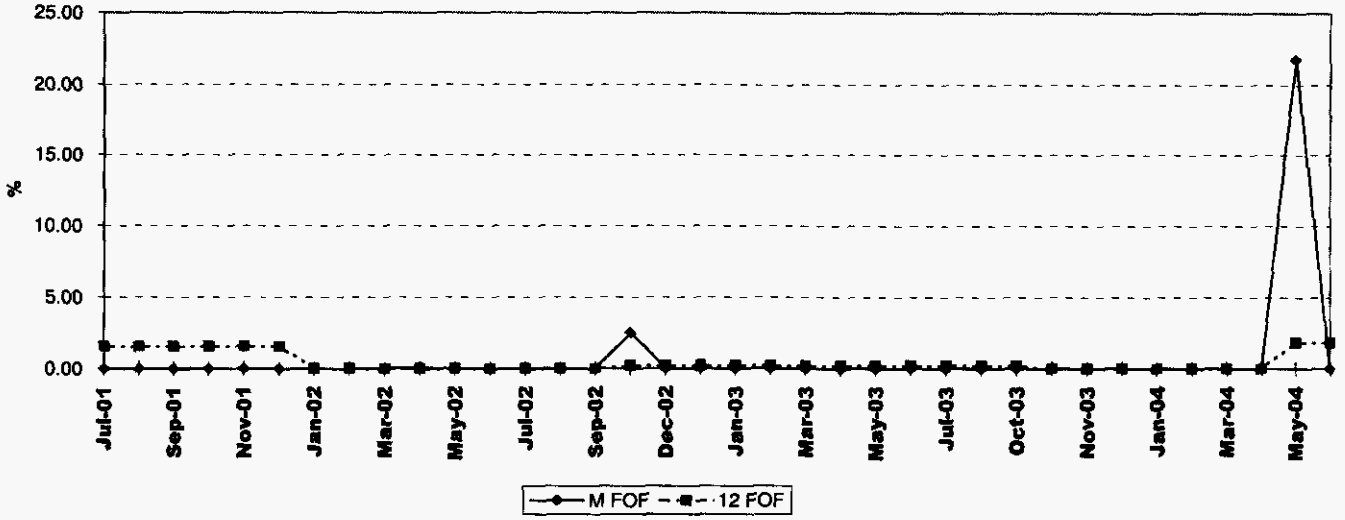
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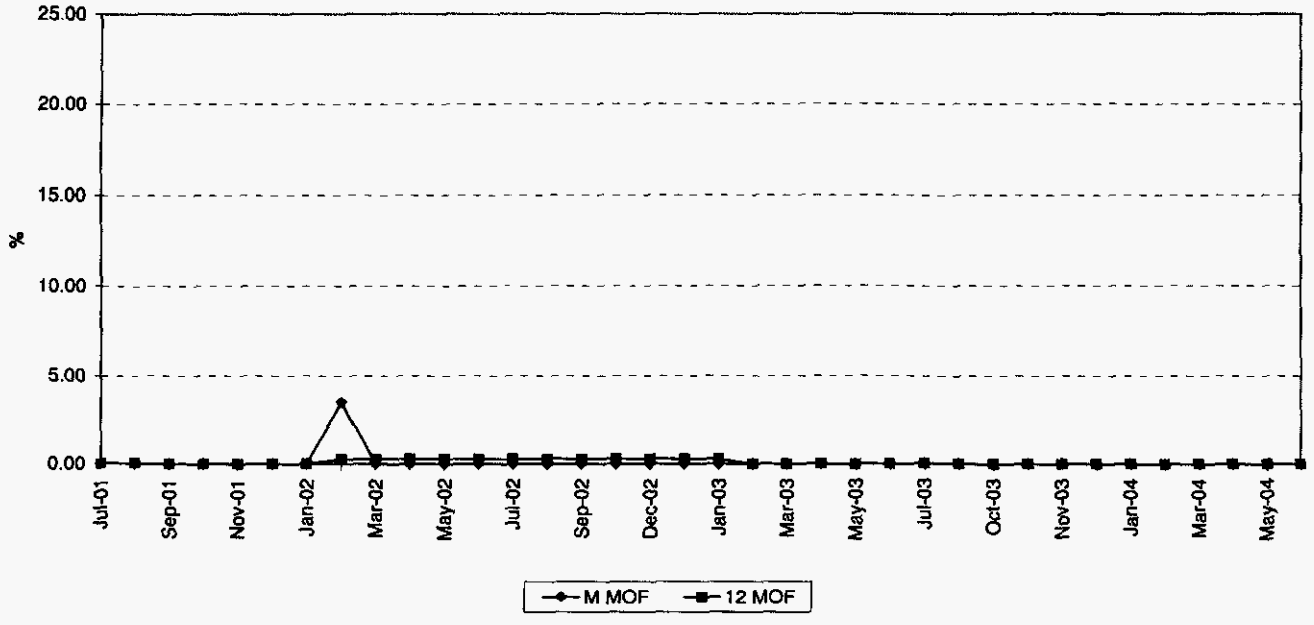
MAINTENANCE OUTAGE FACTOR



PTN 4
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PLANT/UNIT	PLAN OUTAGE*	REASON FOR OUTAGE	LR MW**
Lauderdale 4	03/19/2005 - 03/30/2005	A CT COMBUSTOR INSPECTION (CI) / B CT CI	443
Lauderdale 5	09/24/2005 - 12/04/2005	A CT MAJOR OH / B CT CI / STEAM (ST) GEN STATOR REWIND (GS	442
Manatee 1	09/17/2005 - 11/30/2005	GSR / REBURN UPGRADE	802
Manatee 2	NONE		
Martin 1	01/29/2005 - 04/01/2005	ST TURB IP/ MINOR BOILER/GENERATOR ROTOR REPLACEMENT	813
Martin 2	NONE		
Martin 3	03/12/2005 - 03/17/2005	B CT COMBUSTOR INSPECTION - 50% CURT	233
Martin 4	02/12/2005 - 02/17/2005	A CT COMBUSTOR INSPECTION - 50% CURT	233
Martin 4	03/19/2005 - 03/30/2005	B CT HOT PATH - 50% CURT	233
Scherer 4	NONE		
St. Lucie 1	10/03/2005 - 12/02/2005	Refueling/reactor vessel head replacement	839
St. Lucie 2	NONE		
Turkey Point 3	NONE		
Turkey Point 4	04/09/2005 - 06/13/2005	Refueling/reactor vessel head replacement	693

*Dates are estimated from breaker open to breaker close
**Load Reduction MW are based on the unit's MW rating during the specified outage period

EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT SCHERER UNIT NO. 3

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 13
COMPANY/ F.P.+L.
WITNESS: J.L. Hartman (TLH-1)
DATE: 11-08-04

TLH-1
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC., AS AGENT FOR GEORGIA POWER COMPANY AND GULF POWER COMPANY, AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Georgia Power Company (hereinafter referred to as "Georgia Power"), a Georgia corporation having its principal office and place of business at 241 Ralph McGill Boulevard NE, Atlanta, Georgia 30308, and Gulf Power Company (hereinafter referred to as "Gulf Power" and collectively with Georgia Power referred to as "Seller"), a Maine corporation having its principal office and place of business at One Energy Place, Pensacola, Florida 32520, and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"**Affiliate**" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" – means, with respect to any payment under Section 12.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all

relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"**Agreement**" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"**Alternate Delivery Point(s)**" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.5 or Section 5.6 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"**Alternate Resource(s)**" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.5 or Section 5.6.

"**Available Capacity**" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"**Billing Month**" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"**Btu**" means British Thermal Units.

"**Business Day**" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"**Buyer**" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Buyer Percentage" means 19.57 percent.

"Central Prevailing Time" or **"CPT"** means the local time at any point in Birmingham, Alabama.

"Change in Law" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"Commercially Reasonable" or **"Commercially Reasonable Efforts"** means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"Contemporaneous Agreements" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Franklin Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (acting as agent for Southern Power Company) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Harris Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (acting as agent for Southern Power Company) and Buyer.

"**Contest**" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"**Contract Capacity**" means, for the applicable calendar year, the product of: (i) the Buyer Percentage; and (ii) the applicable Total Facility Capacity, rounded down to the nearest whole MW.

"**Contract Year**" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each twelve (12) Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"**Day**" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"Delivery Day" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"**Delivered Energy**" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule and any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"Delivered Energy Credit" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus

the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

"**Delivery Excuse**" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); or (iii) any directive from the applicable transmission provider and/or the control area operator to cease deliveries of energy from the Facility.

"**Delivery Point**" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"**Effective Date**" has the meaning set forth in the introductory paragraph hereof.

"**Electric Metering Equipment**" means electric meters and associated equipment, including metering transformers and back-up meters.

"**EFMH**" or "**Equivalent Force Majeure Hour**" shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.5.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"**EUH**" or "**Equivalent Unavailable Hour**" shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"**Event of Default**" has the meaning set forth in Section 14.1.

"**Facility**" means Seller's coal fired steam turbine electric generating unit known as Plant Robert W. Scherer Unit No. 3 (as may be modified) and all appurtenant facilities located near Juliette, Georgia which directly interconnects to the Georgia Integrated Transmission System.

"**Facility Delivery Point**" means the substation where the Facility interconnects to the Georgia Integrated Transmission System (or other applicable transmission system) at the transmission system voltage.

"**FERC**" means the Federal Energy Regulatory Commission, or any successor to its functions.

"**Florida Interface**" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"**Force Majeure Capacity**" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the product of: (i) the portion of the Total Facility Capacity that is not available from the Facility as a result of such Force Majeure Event; and (ii) the Buyer Percentage.

"**Force Majeure Event**" has the meaning set forth in Section 13.1.

"**Forced Outage**" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure. A Forced Outage does not include those times that the Facility's capability is reduced (in whole or in part) due to a Force Majeure Event, Delivery Excuse, or during Scheduled Outages or Maintenance Outages. In addition, a Forced Outage

shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Georgia Integrated Transmission System" or **"GITS"** means the electric transmission systems owned individually by Georgia Power, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia, and operated as an integrated transmission system, as well as any successor transmission system.

"Georgia Power" has the meaning set forth in the introductory paragraph hereof.

"Government Agency" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"Guarantor" has the meaning set forth in Section 14.1.

"Guaranty" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 18.

"Gulf Power" has the meaning set forth in the introductory paragraph hereof.

"IIC" means the Southern Company System Intercompany Interchange Contract among the electric operating companies of Southern Company (or any successor arrangement), as the same may be changed or amended from time to time.

"Imaged Agreement" has the meaning set forth in Section 19.17.

"Increased Generation Costs" means [redacted]

[redacted]

"**kW**" means kilowatt(s).

"**kWh**" means kilowatt hour(s).

"**Law**" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"Maintenance Outage" has the meaning set forth in Section 4.2.

"Minimum Schedule Amount" has the meaning set forth in Appendix D.

"MMBtu" means one million Btu.

"Month" means a calendar month.

"Monthly Capacity Payment" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"Monthly Energy Payment" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"Monthly Start Payment" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"Moody's" has the meaning set forth in Section 17.1.

"MW" means megawatt(s).

"MWh" means megawatt hour(s).

"NERC" means the North American Electric Reliability Council, or any successor to its functions.

"OATT" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Operating Committee" has the meaning set forth in Section 4.5.

"Operating Procedures" has the meaning set forth in Section 4.4.

"Outage Capacity" means, for any hour in which a Forced Outage occurs or is continuing, the product of: (i) the portion of the Total Facility Capacity that is not available from the Facility as a result of such Forced Outage; and (ii) the Buyer Percentage.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Robert W. Scherer Units 1 through 4 and all appurtenant facilities located near Juliette, Georgia, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal*. In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance

standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"**S&P**" has the meaning set forth in Section 17.1.

"**Schedule**" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"Schedule Start" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled.

"**Scheduled Energy**" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement.

"**Scheduled Outage**" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"**Scheduling Parameters**" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"**Seller**" has the meaning set forth in the introductory paragraph hereof.

"**Service Commencement Date**" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"**Southern Company**" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"**Southern Company Transmission**" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"**Southern Company Transmission System**" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"**Successful Start**" means each time that Seller goes from delivering no energy to delivering an amount of energy at least equal to the Minimum Scheduling Amount during [redacted] of Buyer's Schedule (or such lesser amount of time for which Buyer has requested at least the Minimum Scheduling Amount); provided, however, if Seller interrupts the delivery of energy during Buyer's Schedule (other than pursuant to Buyer's request or a Delivery Excuse), a Successful Start shall not be deemed to have occurred when delivery is resumed pursuant to the same Schedule.

"**Taxes**" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"**Term**" has the meaning set forth in Section 2.1.

"**Total Facility Capacity**" means, for each calendar year, the full load capacity rating (or equivalent rating) of the Facility (including the portions of the Facility owned by Gulf Power and Georgia Power) for such year as set forth in the applicable informational filing(s) under the

IIC made at FERC, adjusted to transmission voltage level. Total Facility Capacity (as may be modified) shall be effective for each applicable calendar year beginning on January 1 of such year.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.5.1 in response to the Forced Outage causing Outage Capacity to exist, less the Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term").

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 Effect of Termination. Subject to the exercise of a non-defaulting Party's rights under Section 14.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 Sale and Purchase of Capacity. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 Sale and Purchase of Energy. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance

and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"). Such maintenance and outages shall be scheduled in accordance with Prudent Industry Practices. Prior to or during any Contract Year, Seller may reschedule any Scheduled Outages in accordance with Prudent Industry Practices.

4.2 Maintenance Outages. [redacted]

4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than six (6) months before the Service Commencement Date.

Such Operating Procedures shall be completed no later than thirty (30) Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages and hours of Delivery Excuse.

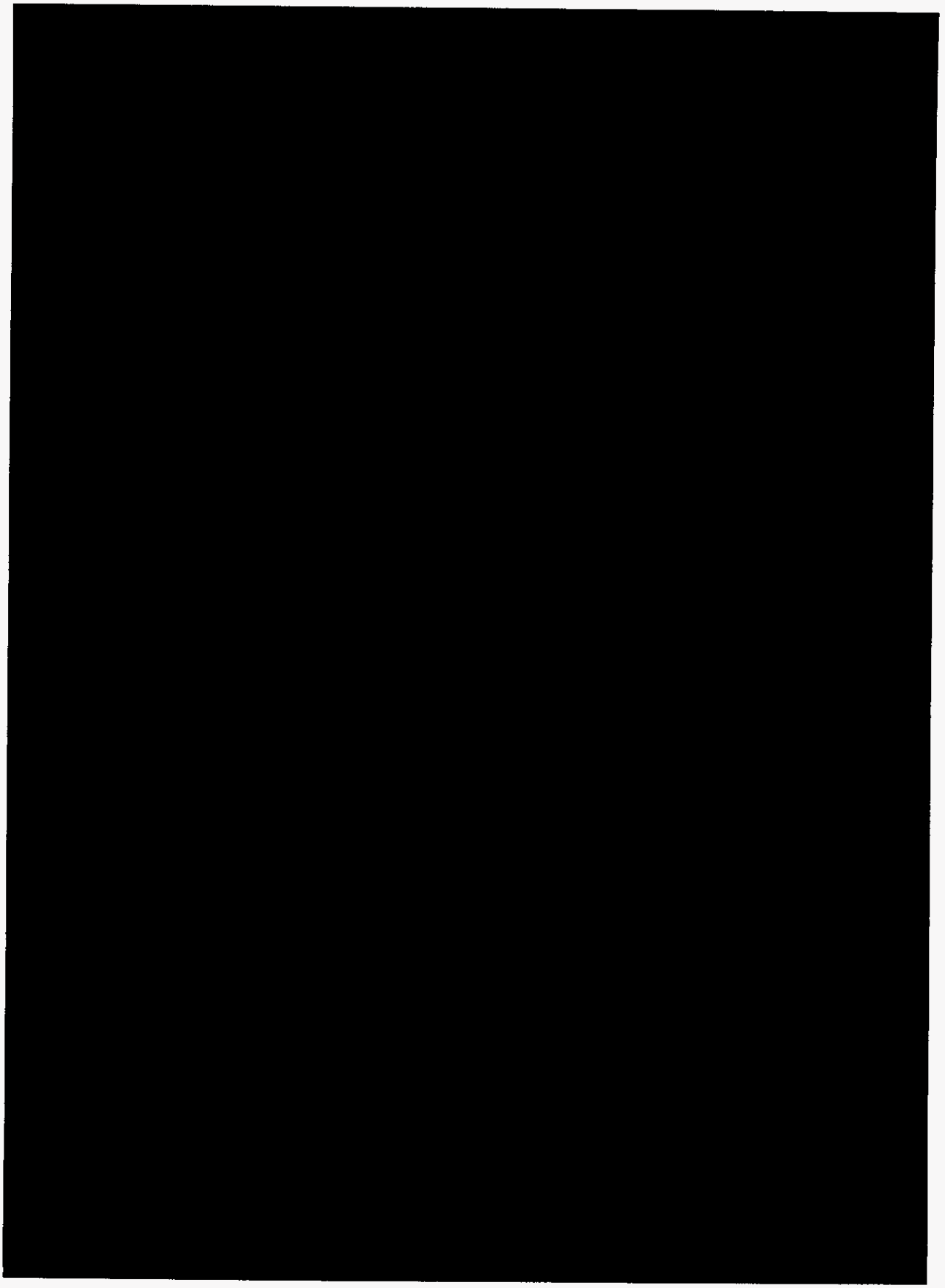
4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone), and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

5.1.1 [redacted]

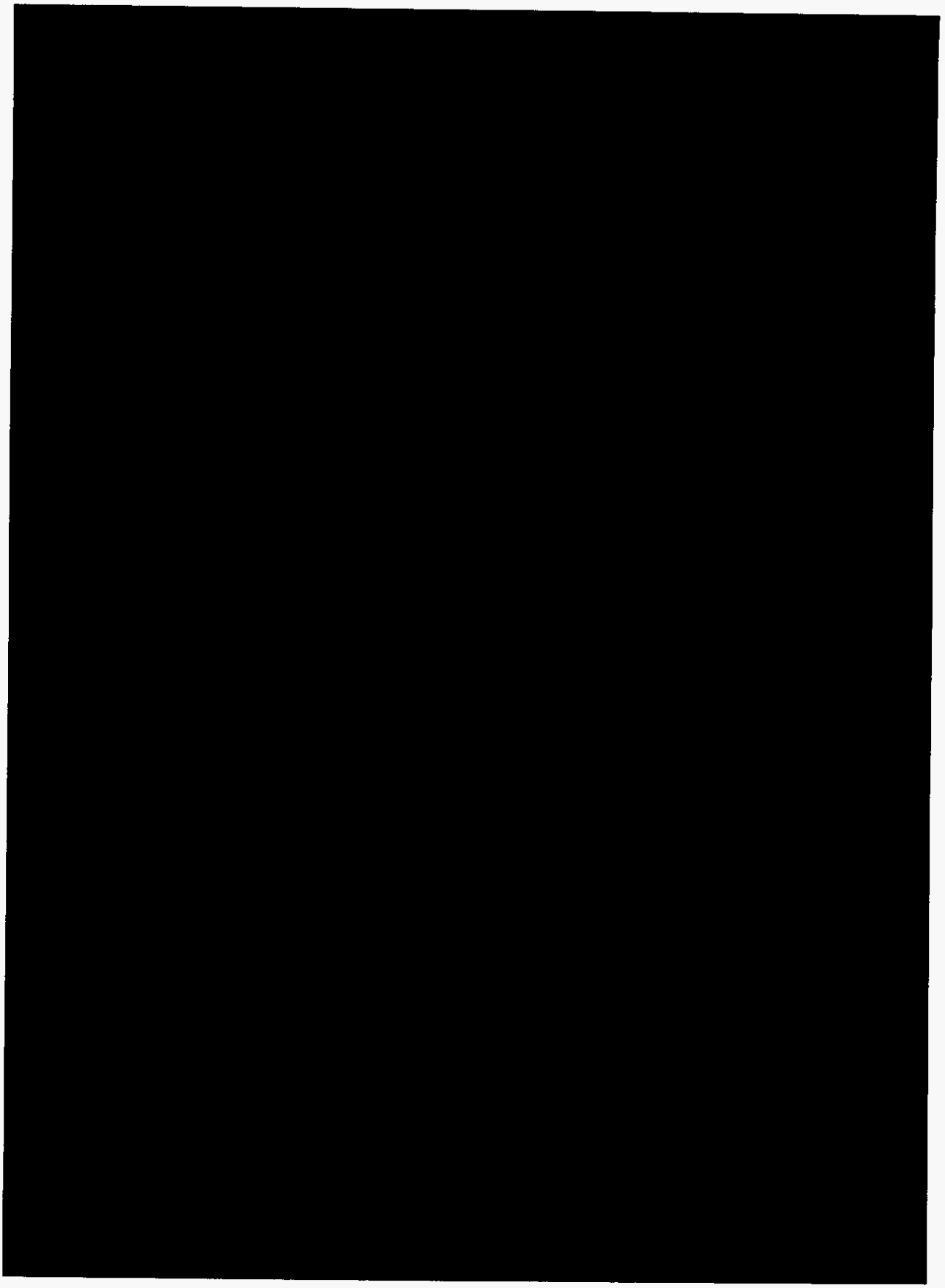


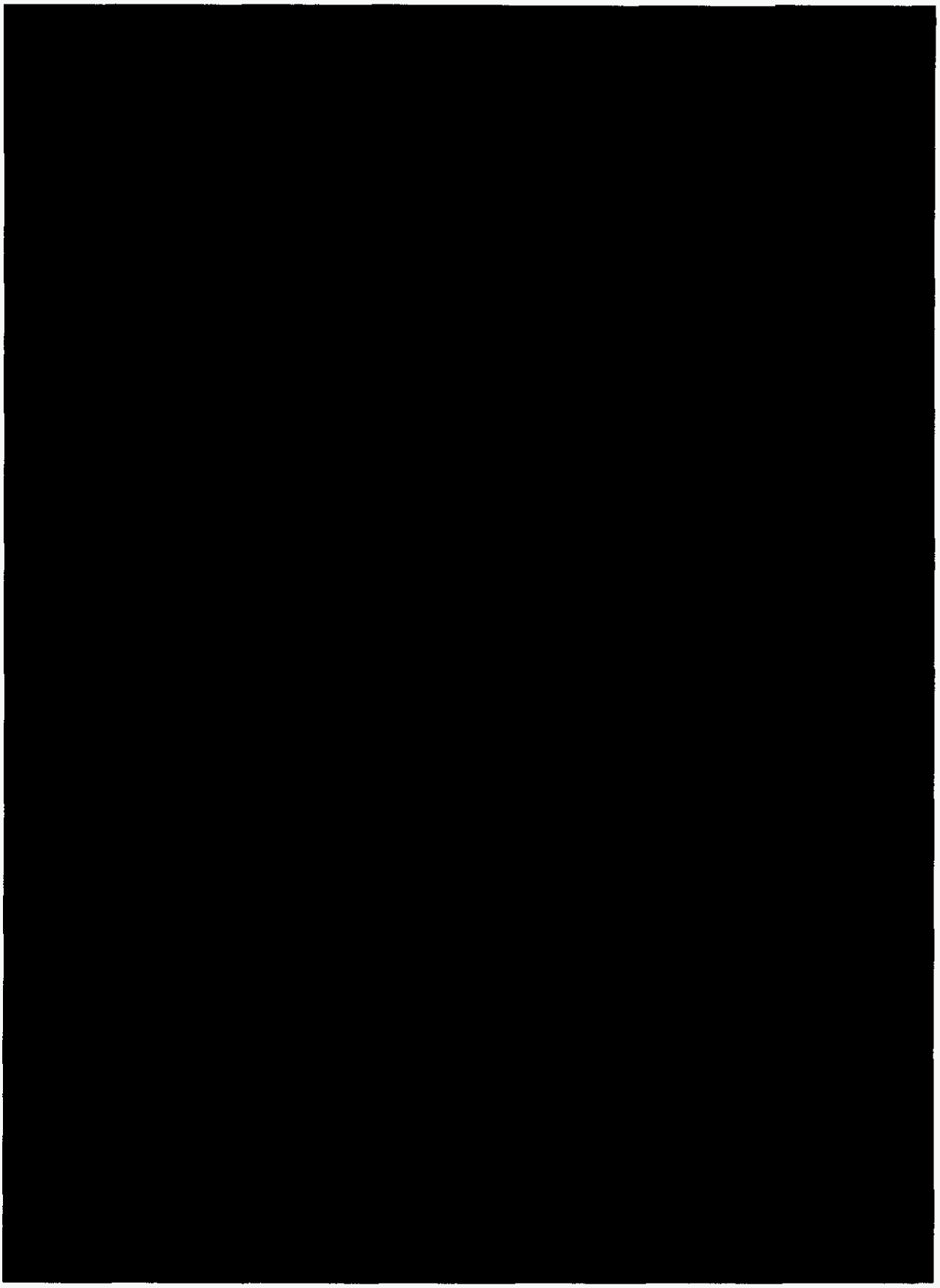
5.2 **Transmission and Scheduling Requirements.** Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

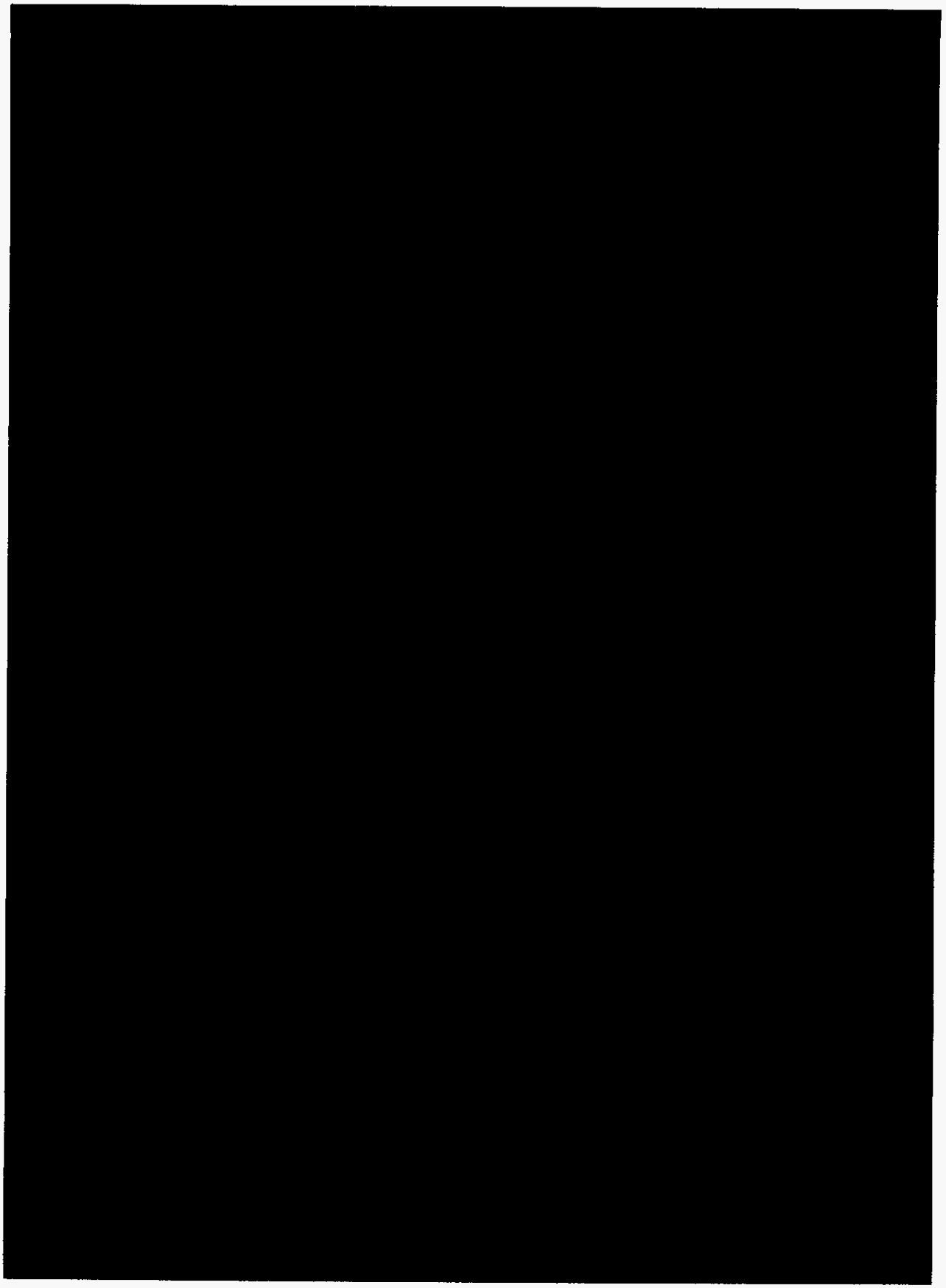
5.3 **Costs and Expenses.** Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

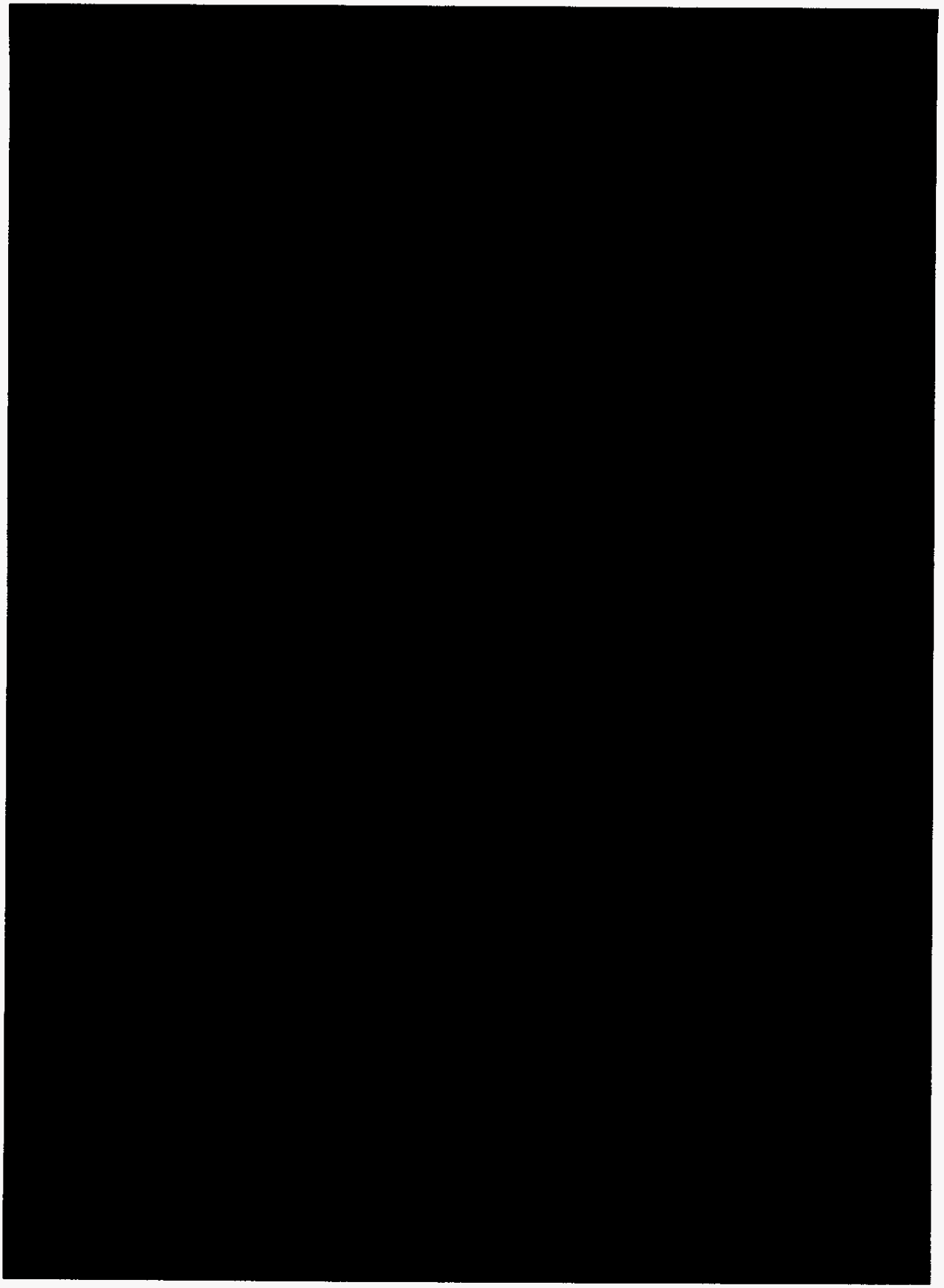
5.4 **Delivery of Energy.** Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.5 [redacted]









[redacted]

5.7 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.8 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.9 Force Majeure Event.

5.9.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.5 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.9.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.10 Forced Outages and Unavailable Capacity.

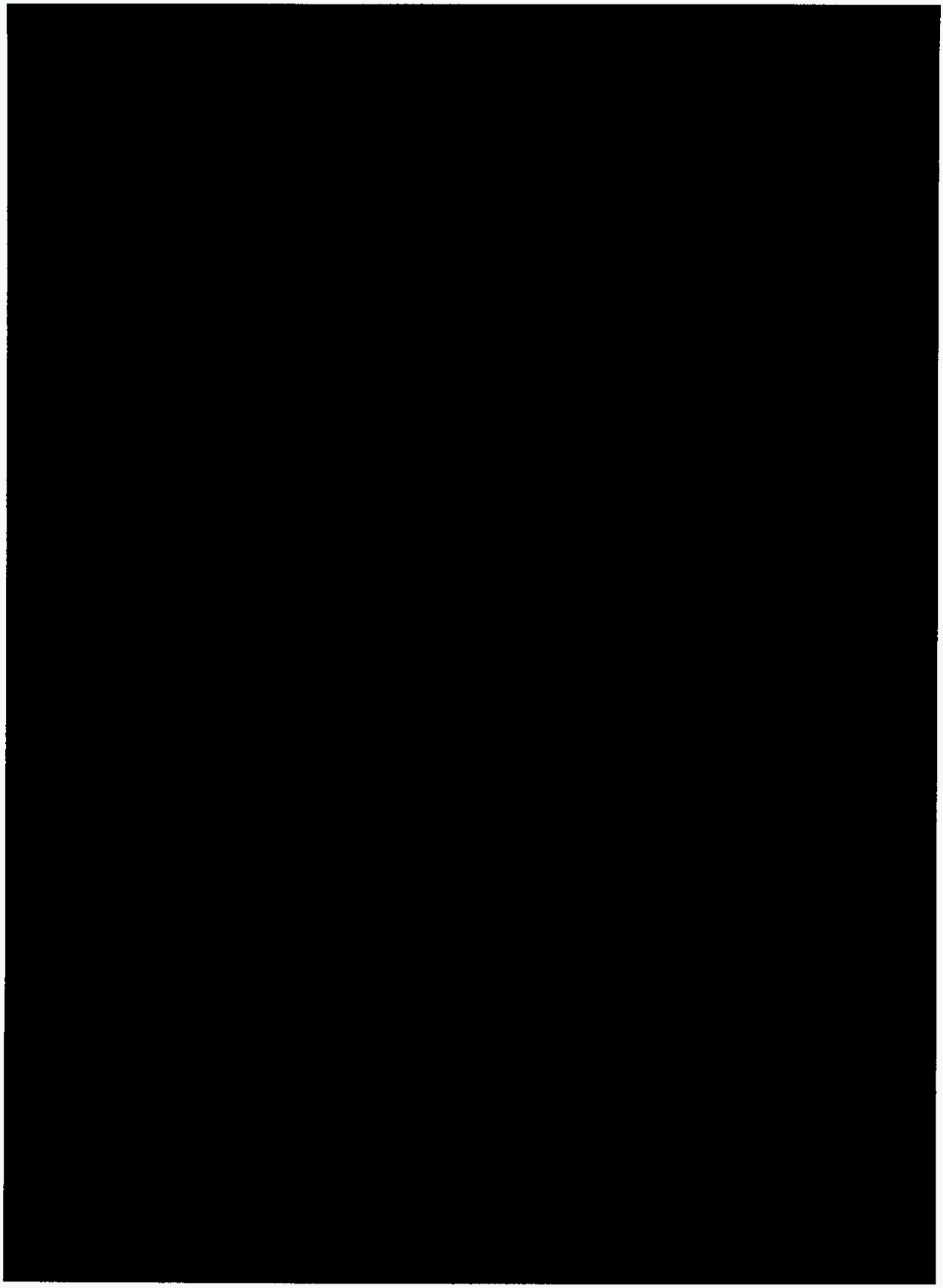
5.10.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Forced Outage that is expected to result in Outage Capacity and the estimated duration of such outage; (ii) the cessation of such Forced Outage; and (iii) if requested by Buyer within 30 Days after the outage and if known to Seller, the cause of such outage.

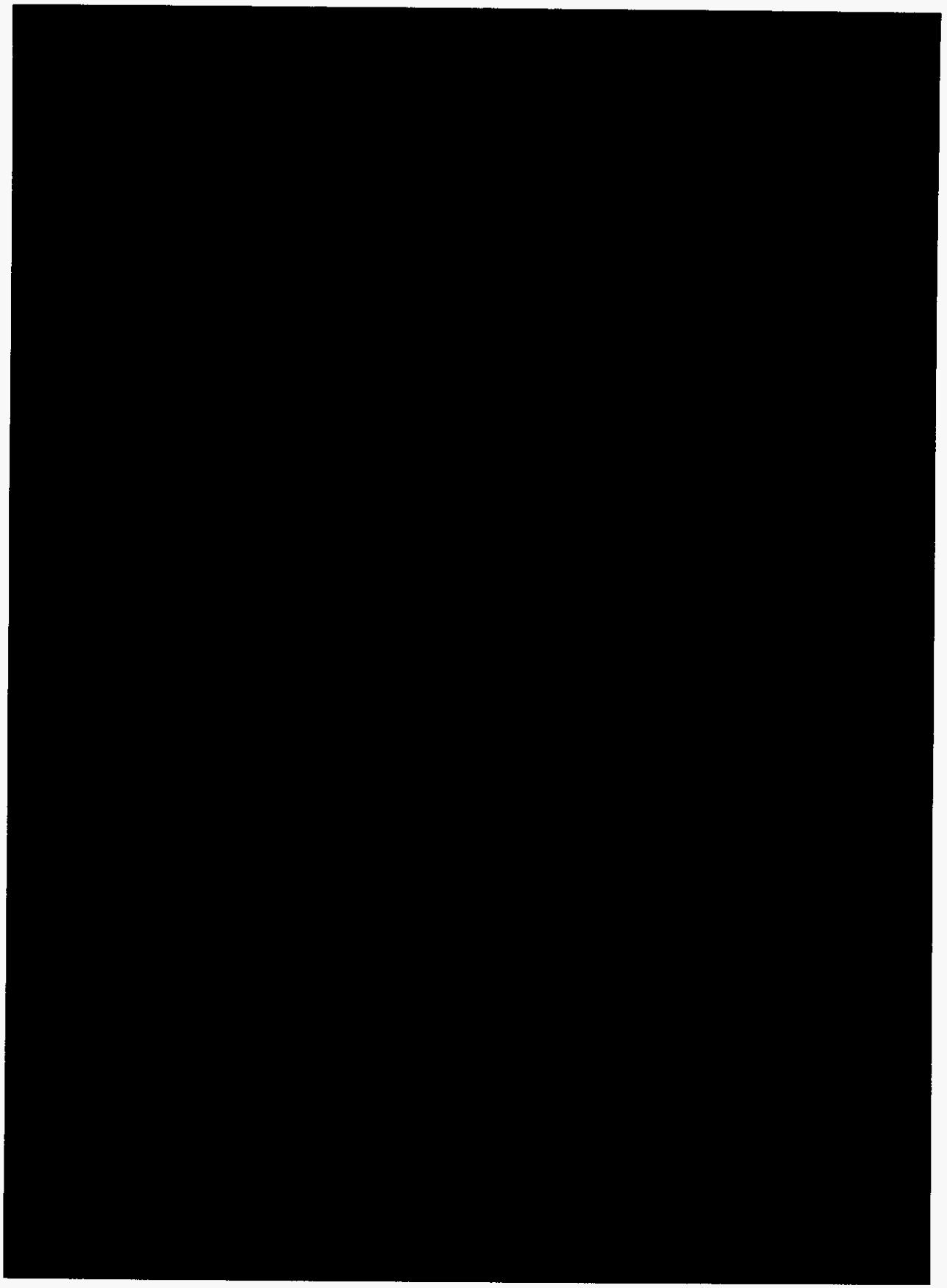
5.10.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall be the [redacted]

5.11 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive, or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.12 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.13 [redacted]





[redacted]

ARTICLE 6

PAYMENTS

6.1 **Capacity Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 **Energy Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 **Start Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., a Forced Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated

with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 165 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's

notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate and include any and all documentation of such Total Cost provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 165 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

[redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted]

Buyer shall notify Seller of such election within three (3) Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted] MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted] MW, Seller shall be entitled to either: [redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other

Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are

Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

ARTICLE 8

ELECTRIC METERING

8.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

8.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

8.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

8.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 9

BILLING AND PAYMENT

9.1 **Timing and Method of Payment.** Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable on [redacted] ("Payment Due Date"). Such invoice shall include adjustments (either a charge or a credit, as applicable) as expressly provided pursuant to Appendix B. If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

9.2 **Late Payment.** Amounts that are owed Seller shall, if not remitted within the time period specified under Section 9.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 19.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

9.3 **Disputed Billings.** In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. [redacted]

[redacted]

9.4 **Adjustments.** If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within thirty (30) Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 19.7 from the date that the undercharge or overcharge actually occurred.

9.5 **Audit Rights.** Subject to Section 8.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 10

REGULATORY

10.1 Initial Approval of the Florida Public Service Commission.

10.1.1 No later than [redacted] after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

10.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

10.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 10.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of

the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

10.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 10.1.1 through 10.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

10.1.5 After the procedures in Sections 10.1.1, 10.1.2, and 10.1.3 (as applicable) have been completed, except as provided under Section 10.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

10.2 Changes in Agreement. Except for any changes pursuant to Section 10.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

10.3 Federal Energy Regulatory Commission.

10.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

10.3.2 Impacted Party may exercise its Section 205 rights provided under Section 10.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter

event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

10.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 11

CHANGE IN LAW

11.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

11.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within six (6) Months after identifying such costs, notify Buyer of: (a) the

applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within sixty (60) Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within thirty (30) Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 16.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

11.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than thirty (30) Days thereafter, Seller may initiate a Change in

Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

11.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 12

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

12.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and provision of

capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

12.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

12.3 Limitation of Liability.

12.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

12.3.2 SUBJECT TO SECTION 14.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

12.3.3 In the event that any provision of this Section 12.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 12.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 12.2 or limit the remedies set forth in this Agreement for an Event of Default.

12.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 13

FORCE MAJEURE EVENT

13.1 Force Majeure Event Defined.

13.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

13.1.2 Notwithstanding anything contained in Section 13.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

13.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

13.2.1 The non-performing Party shall give the other Party written notice within three (3) Business Days of the commencement of the Force Majeure Event, with available details to be supplied within fifteen (15) Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

13.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

13.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

13.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

13.3 Effect of Force Majeure Event.

13.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

13.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

[redacted]

13.4 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARTICLE 14

EVENT OF DEFAULT

14.1 **Event of Default.** The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

14.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within fifteen (15) Days after receiving written notice of such failure from the Party to which such payments are due;

14.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

14.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its

debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

14.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within sixty (60) days of the filing thereof;

14.1.5 The failure of any Party to comply with the requirements of Article 18 regarding creditworthiness and/or security;

14.1.6 The failure of a Party to comply with the requirements of Article 17 regarding assignment;

14.1.7 Any representation or warranty made by a Party under Article 15 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within thirty (30) Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

14.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

14.1.9 [redacted]

[redacted]

14.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for thirty (30) Days after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of thirty (30) Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed ninety (90) Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 14.1.10 shall not apply to: (i) any event described in Sections 14.1.1 through 14.1.9; (ii) any event described in Sections 5.9 and 5.10 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 14.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party."

14.2 Exclusive Remedies.

14.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

14.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than twenty (20) Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 19.3 and 19.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in Sections 14.2.3 or 14.2.4 below. The exercise by a Party of its rights under this Section 14.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

14.2.3 With respect to an Event of Default by or attributable to Buyer, within fifteen (15) Days after Seller's notice under Section 14.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within thirty (30) Days after such notice,

the two independent parties shall select a third independent party to determine the Seller's Damages. Within sixty (60) Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within five (5) Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 16 and the arbitration order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within three (3) Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within three (3) Business Days of the relevant arbitration finding or order. As used herein, "Seller's Damages" [redacted]

14.2.4 With respect to an Event of Default by or attributable to Seller, within fifteen (15) Days after Buyer's notice under Section 14.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within thirty (30) Days after such notice,

the two independent parties shall select a third independent party to determine the Buyer's Damages. Within sixty (60) Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within five (5) Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arithmetic procedures of Article 16 and the arithmetic order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within three (3) Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within three (3) Business Days of the relevant arbitration finding or order. As used herein, "Buyer's Damages" means [redacted]

ARTICLE 15

REPRESENTATIONS AND WARRANTIES

15.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

15.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

15.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

15.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a

breach or default under any evidence of its indebtedness or any other agreement or instrument to which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

15.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

15.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 16

DISPUTE RESOLUTION

16.1 Senior Officers.

16.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and,

unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

16.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

16.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

16.2 Arbitration.

16.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 16.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will

be made by notice to the other Party and to the AAA within ten (10) Days or, in the case of payment disputes, five (5) Days after the date of the giving of notice of the demand for arbitration. The arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within ten (10) Days or, in the case of payment disputes, five (5) Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

16.2.2 Subject to Section 14.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 19.2; provided further, notwithstanding any provision in Article 19, Confidential Information, to the extent relevant, may be disclosed by

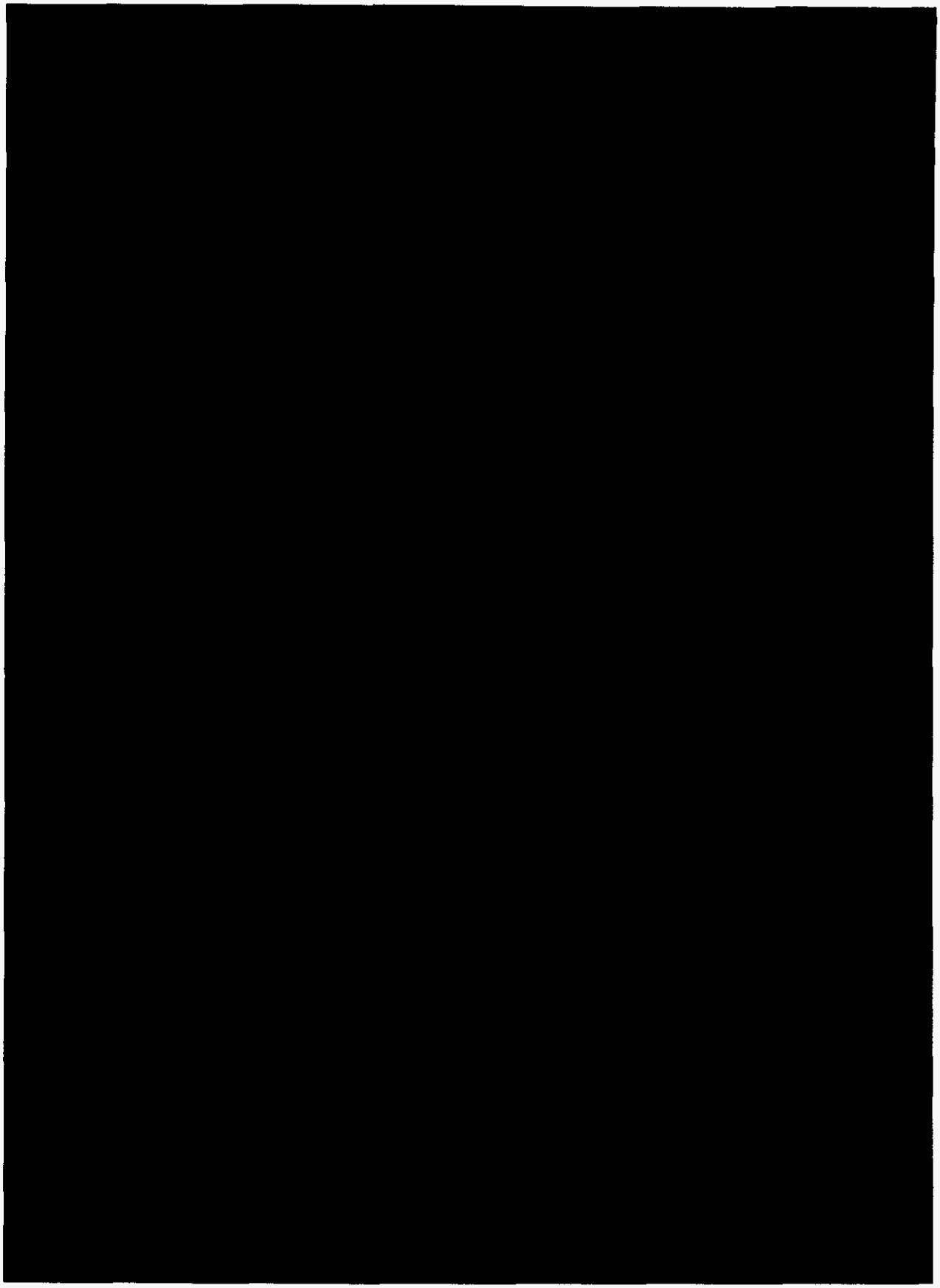
any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

16.3 **Binding Nature of Proceedings.** Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 16.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 17

ASSIGNMENT

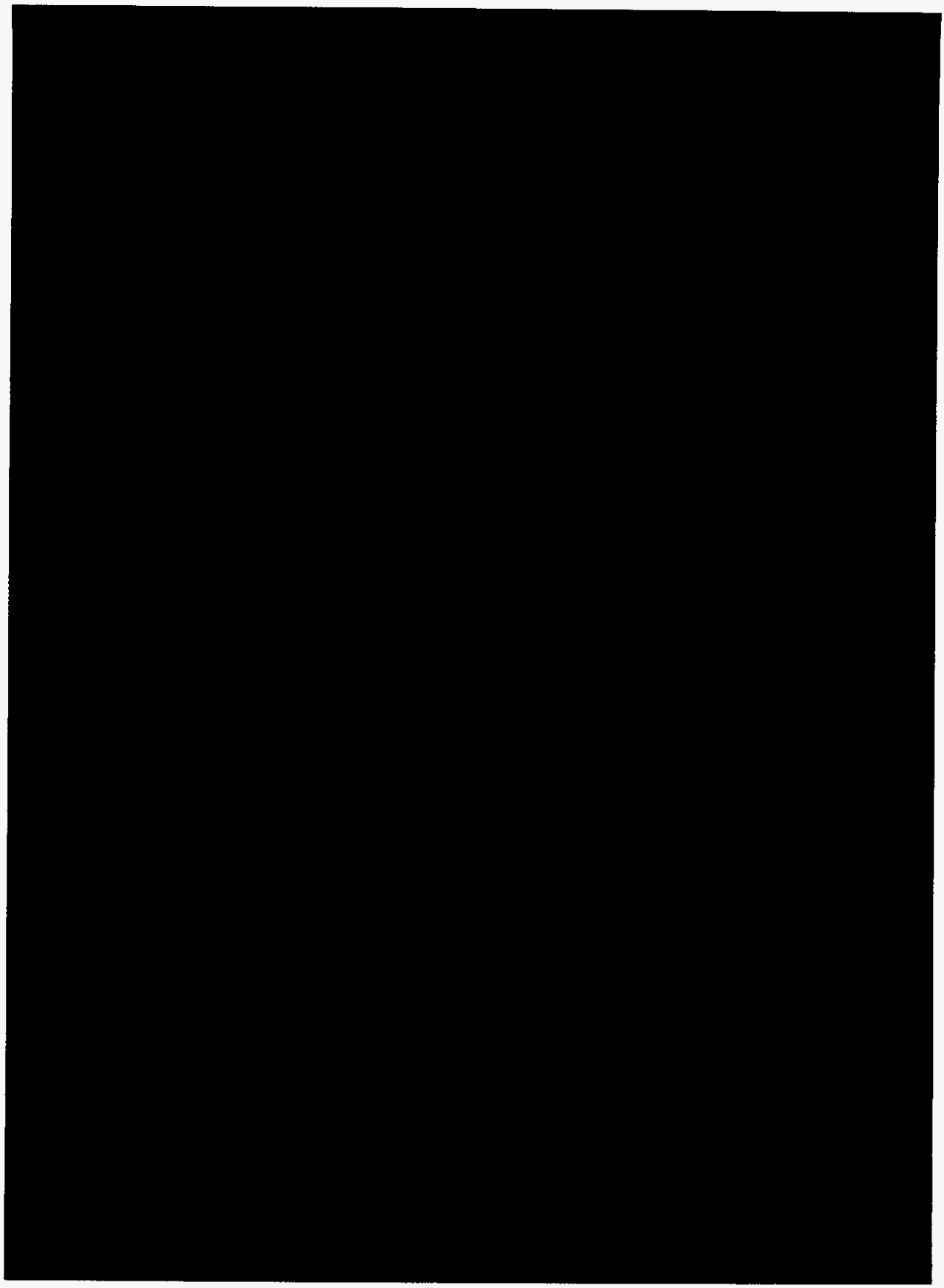
17.1 **Assignment.** Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with at [redacted]

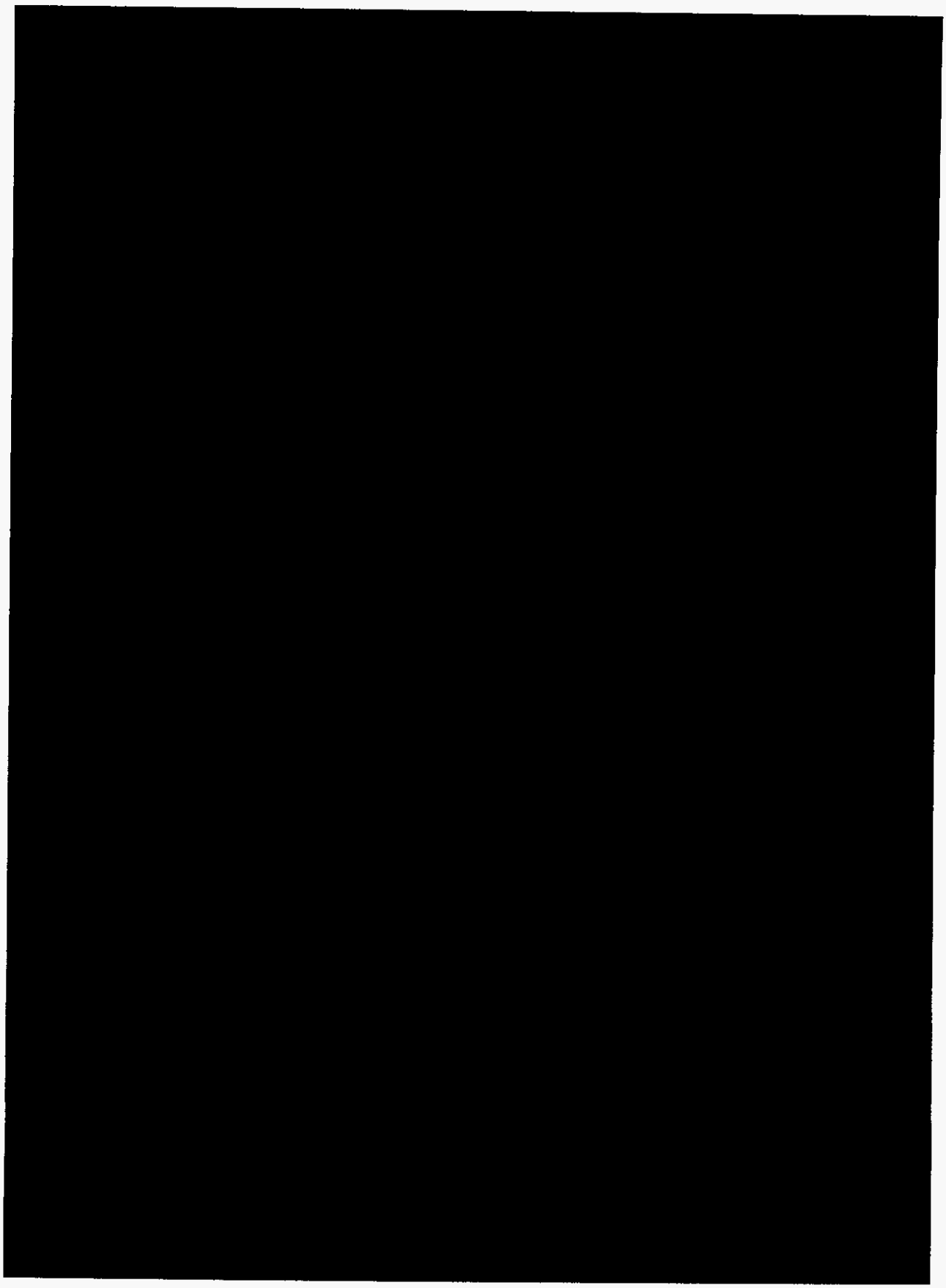


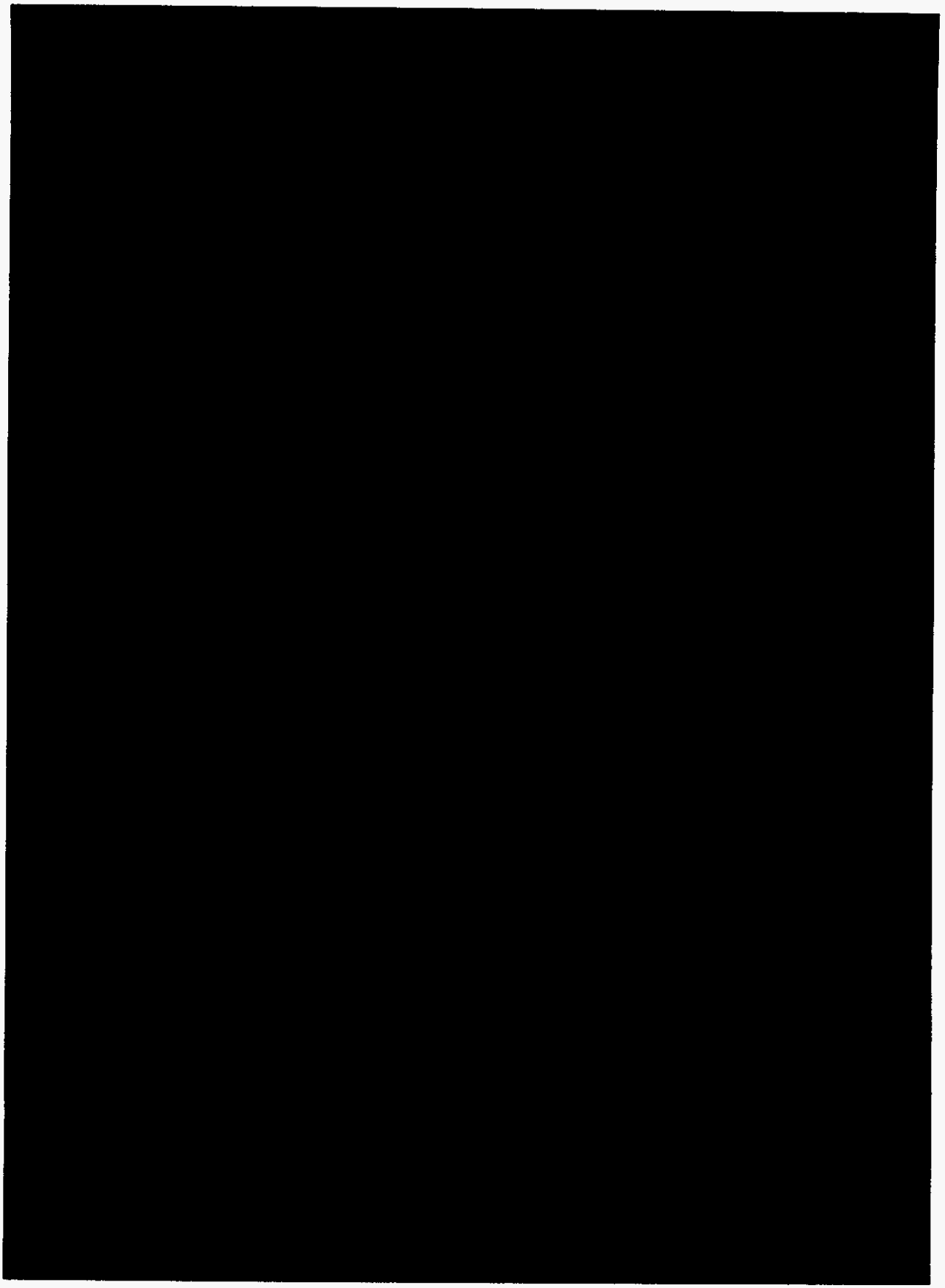
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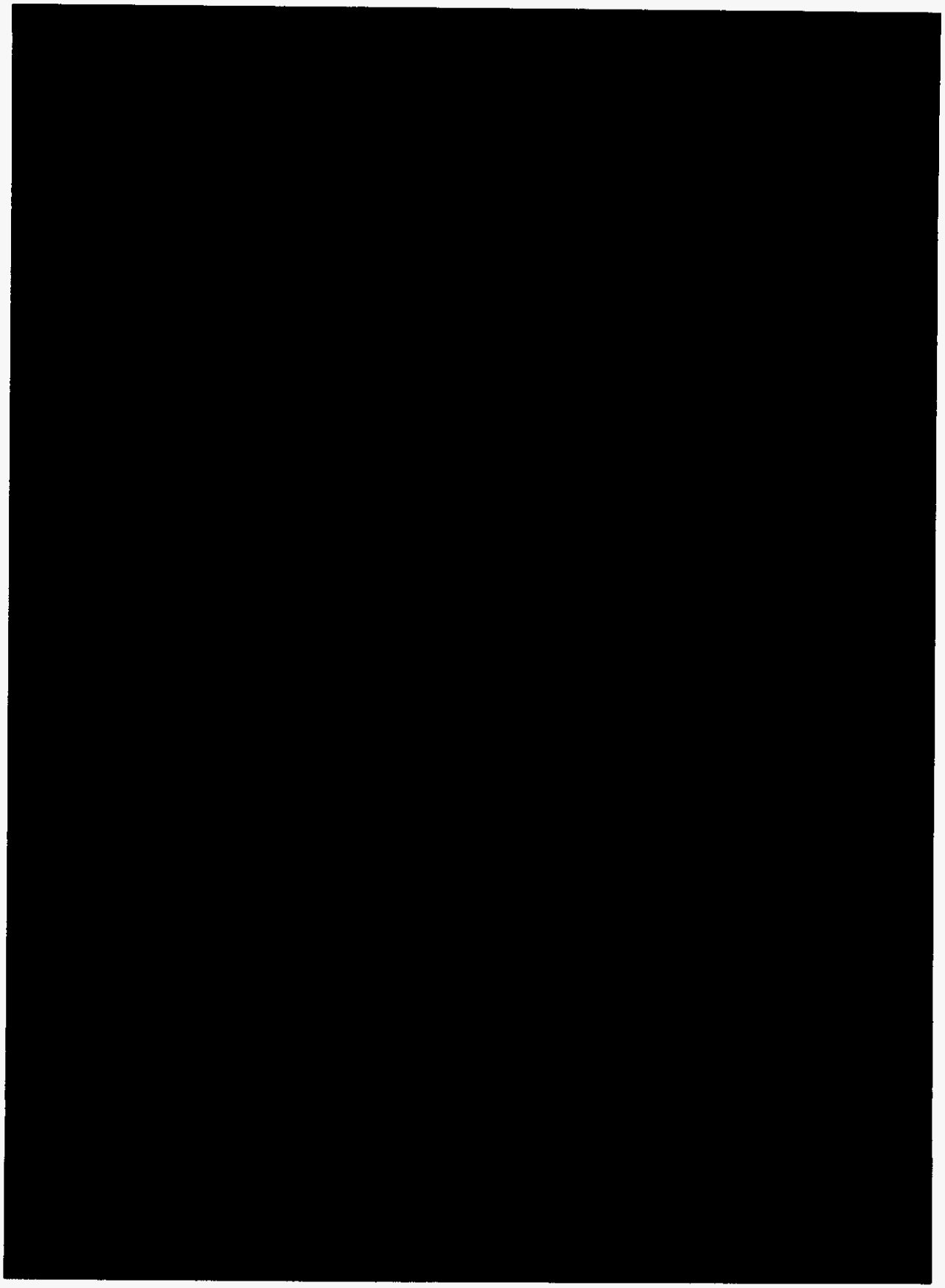
who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

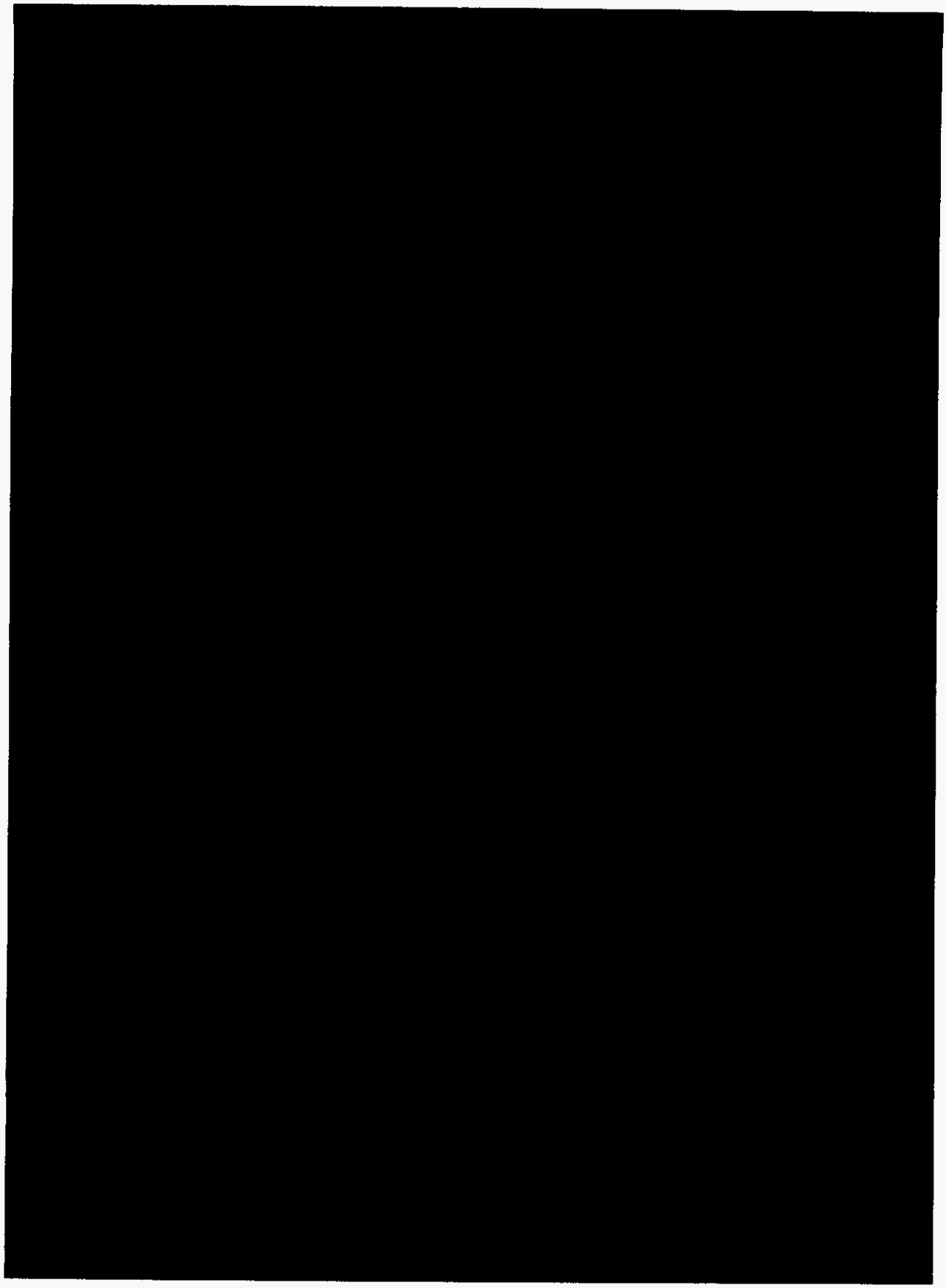
17.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions"). Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

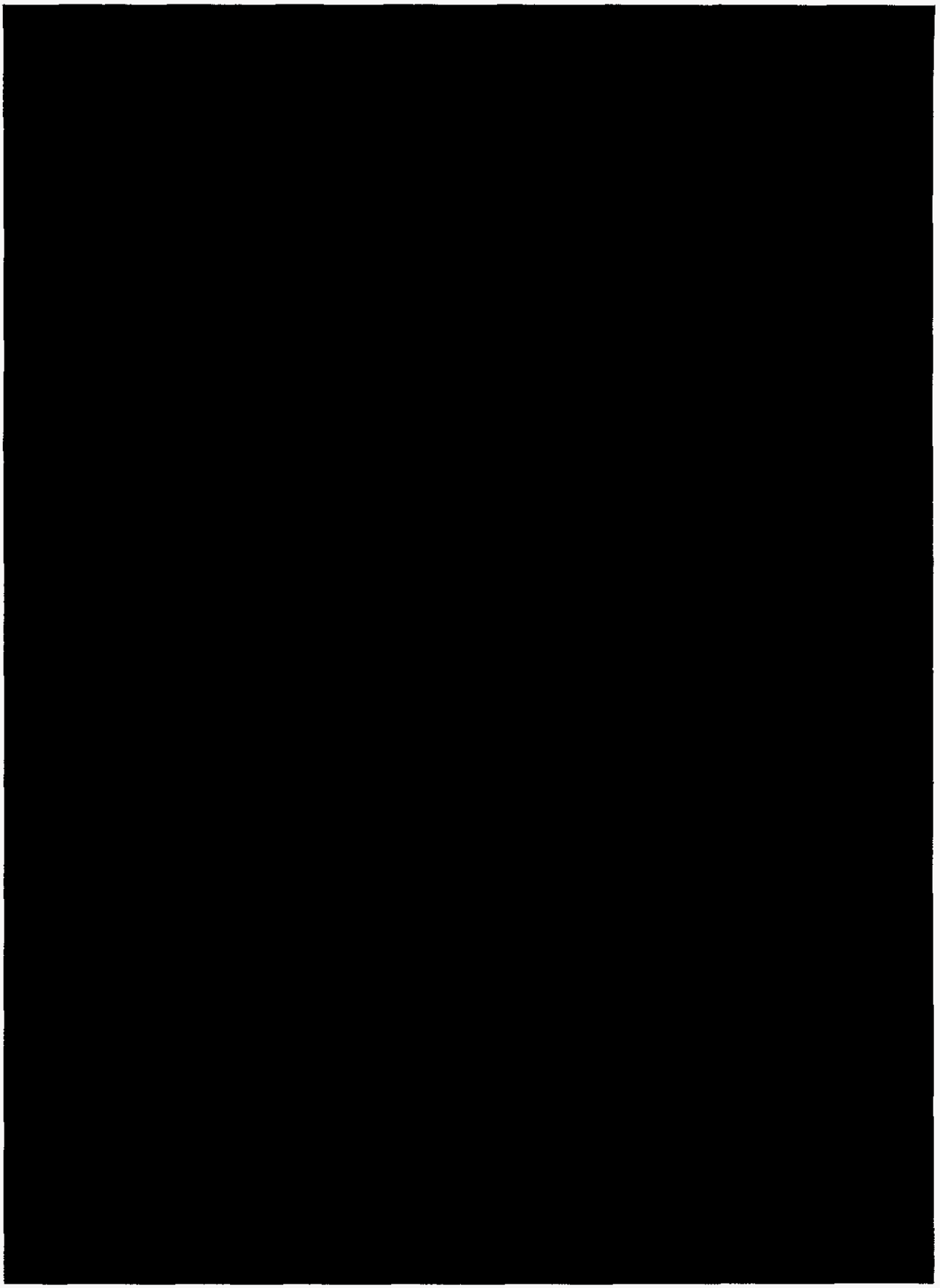


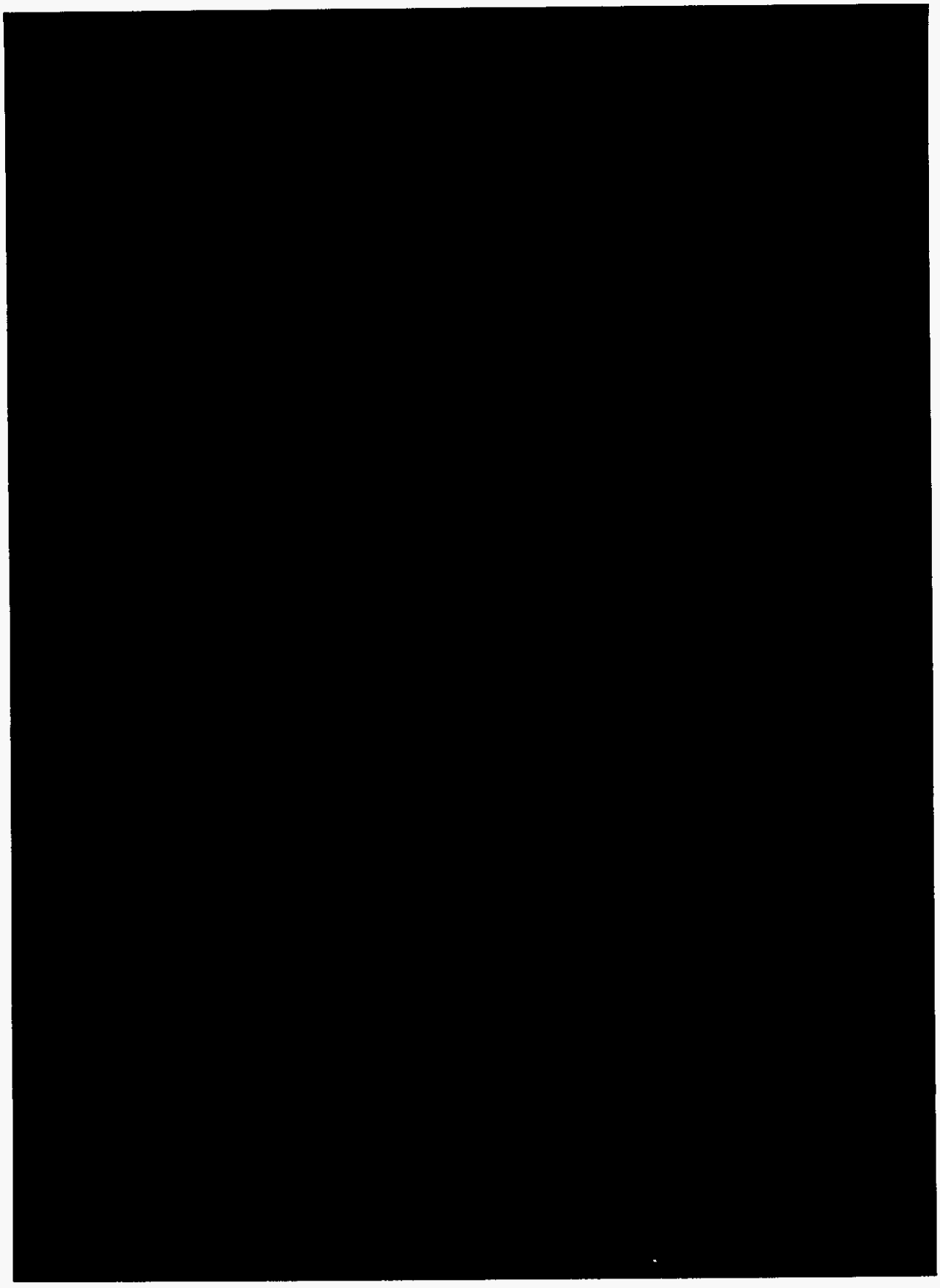


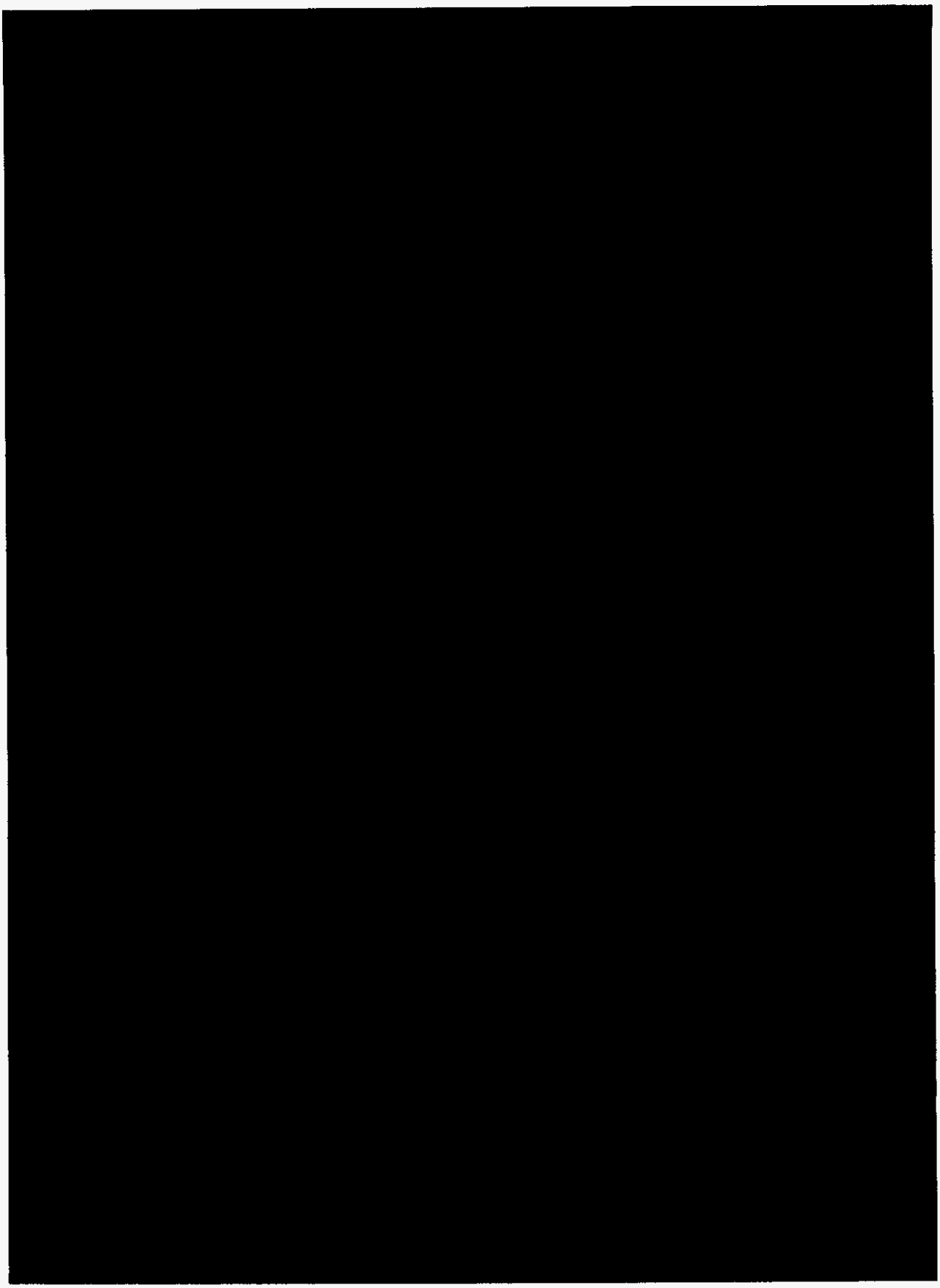


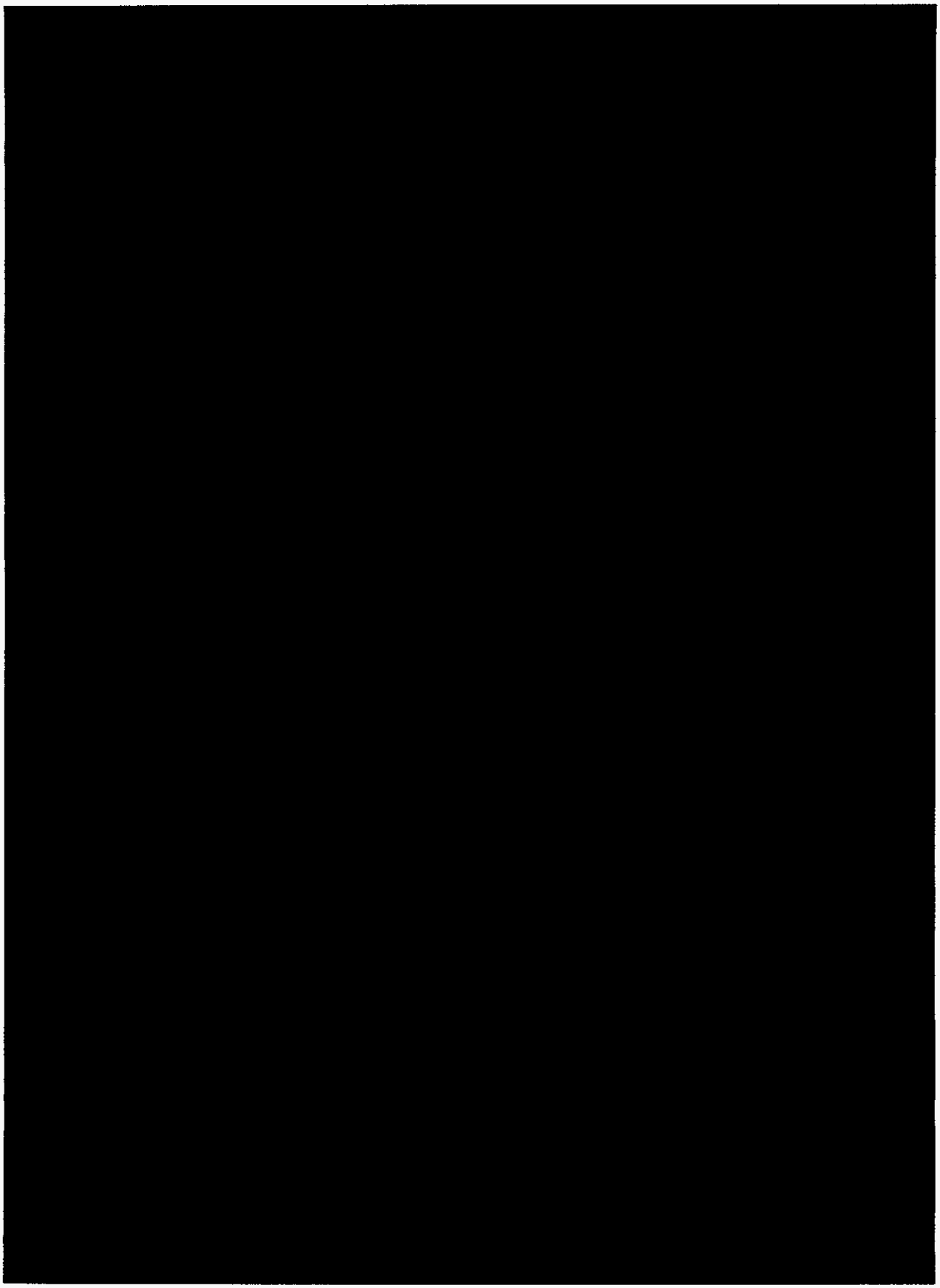












ARTICLE 19

MISCELLANEOUS

19.1 Governing Law; Waiver of Jury Trial. THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE, REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

19.2 Confidentiality.

19.2.1 Scope of Protection.

(i) For purposes of this Section 19.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller

when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Georgia Power or Gulf Power or any of their Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Georgia Power or Gulf Power or any of their Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 19.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SEARUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to

maintain such confidentiality; and (iii) Seller has notified Buyer of its intention to release such information no less than five (5) Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the reasonable judgment of Buyer should have access to such Seller Confidential Information and are bound by an obligation to maintain such confidentiality provided that Buyer shall be responsible for any use or disclosure of such Seller Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 19.2; provided further that nothing contained herein shall prohibit Buyer from providing Seller Confidential Information to the NERC or SEARUC solely to the extent that (i) Buyer determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability, (ii) such entity is obligated to maintain such confidentiality, and (iii) Buyer has notified Seller of its intention to release such information no less than five (5) Business Days prior to the release subject to the requirements of applicable law and regulation.

(iv) Notwithstanding the foregoing, either Party may disclose Confidential Information (i) to the extent relevant, to the independent parties determining Seller's Damages or Buyer's Damages (as appropriate), and (ii) to its and its Affiliates' employees, officers, directors, accountants, counsel and other advisors who need to know such information in connection with the performance of their duties or services for the disclosing Party or its Affiliates; provided, however, that such Persons shall be required to maintain the confidentiality of such information consistent with the requirements of this Agreement..

19.2.2 Required and Other Disclosure.

(i) Notwithstanding anything in this Section 19.2 to the contrary, if Buyer is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Seller Confidential Information or otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent

with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section 19.2 to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure

request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 19.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was

previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 19.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 19.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to

disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the

Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

The obligations under this Section 19.2 with respect to any Party shall survive until the earlier of [redacted]

19.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 12.2 and 12.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

19.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for

the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

19.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

19.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

19.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

19.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual

understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

19.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

19.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

19.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

19.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

19.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

19.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President and General Counsel
Georgia Power Company
241 Ralph McGill Boulevard
Atlanta, Georgia 30308

Telephone: 404-506-2700
Facsimile: 404-506-7985

And

Vice President, Chief Financial Officer and Comptroller
Gulf Power Company
1 Energy Place
Pensacola, Florida 32520

Telephone: 850-444-6385
Facsimile: 850-444-6744

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305 552-2905

Either Party may change the information set forth in this Section 19.14 by giving written notice to the other Party in the manner prescribed by this Section.

19.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

19.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract

construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

19.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

19.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision

or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

19.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer sixty (60) Days written notice in which event Southern Company Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

19.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

19.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix G. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Georgia Power Company and
Gulf Power Company

BY: _____

NAME: William N. McKenzie

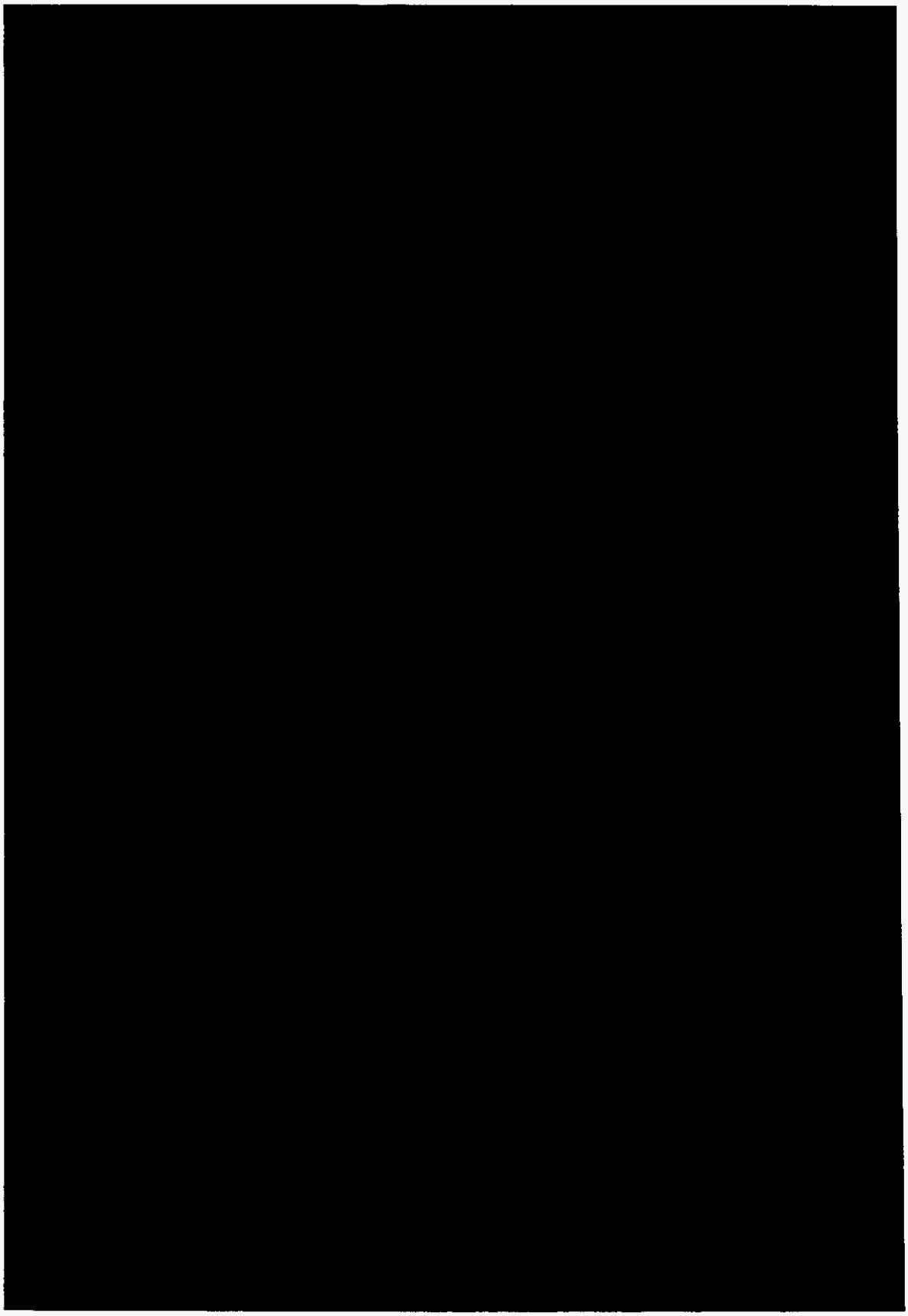
TITLE: Vice President

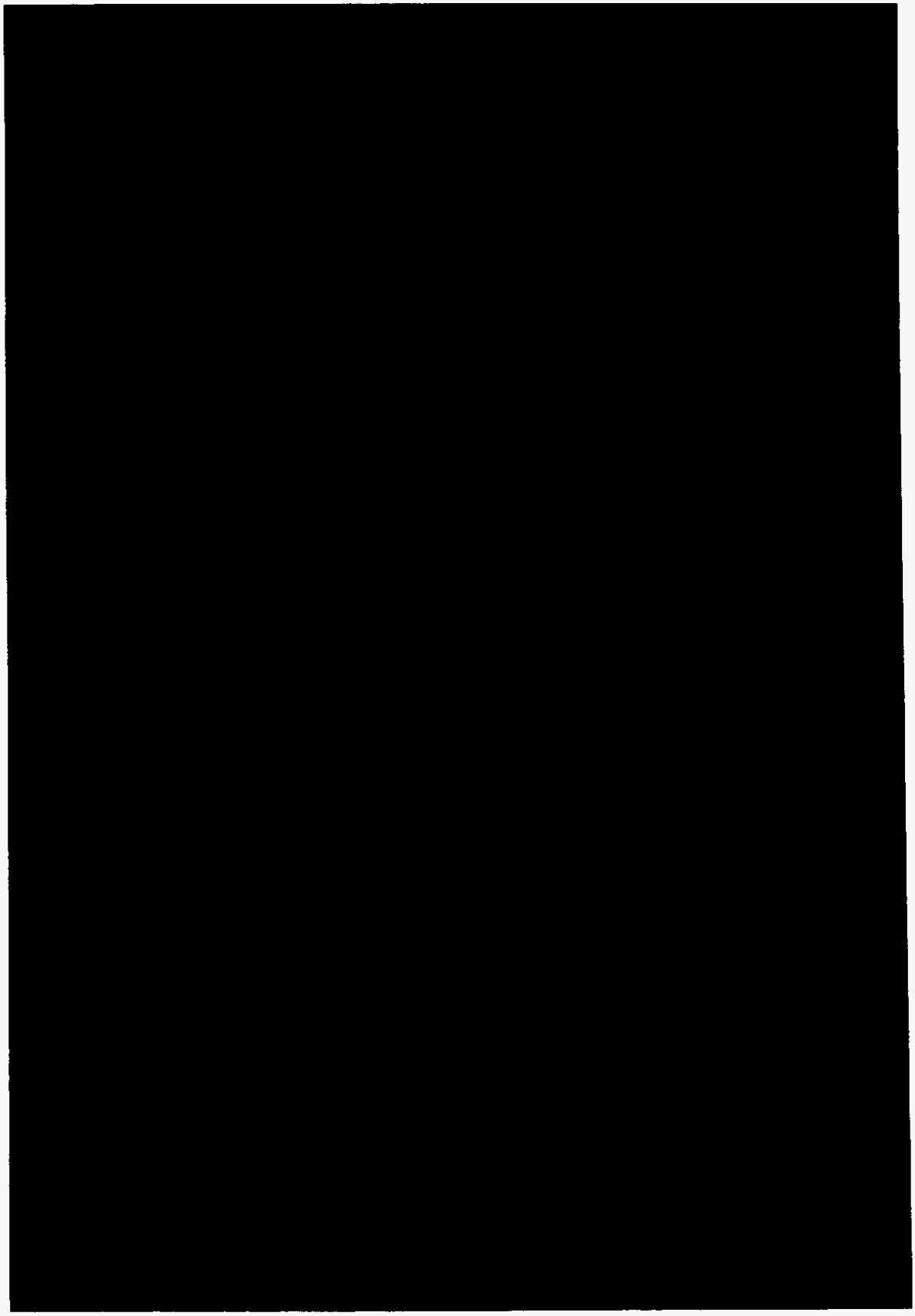
FLORIDA POWER & LIGHT COMPANY

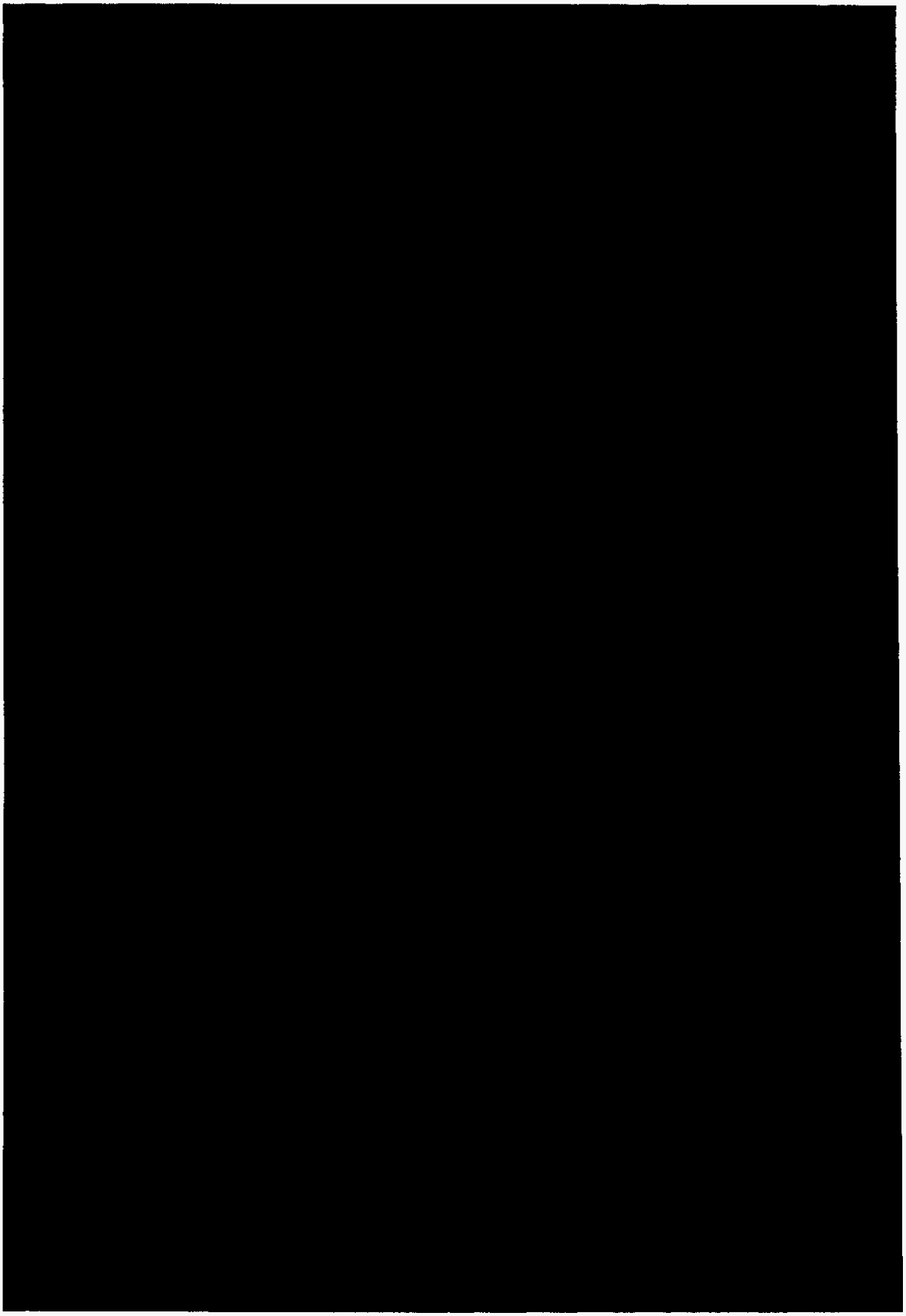
BY: _____

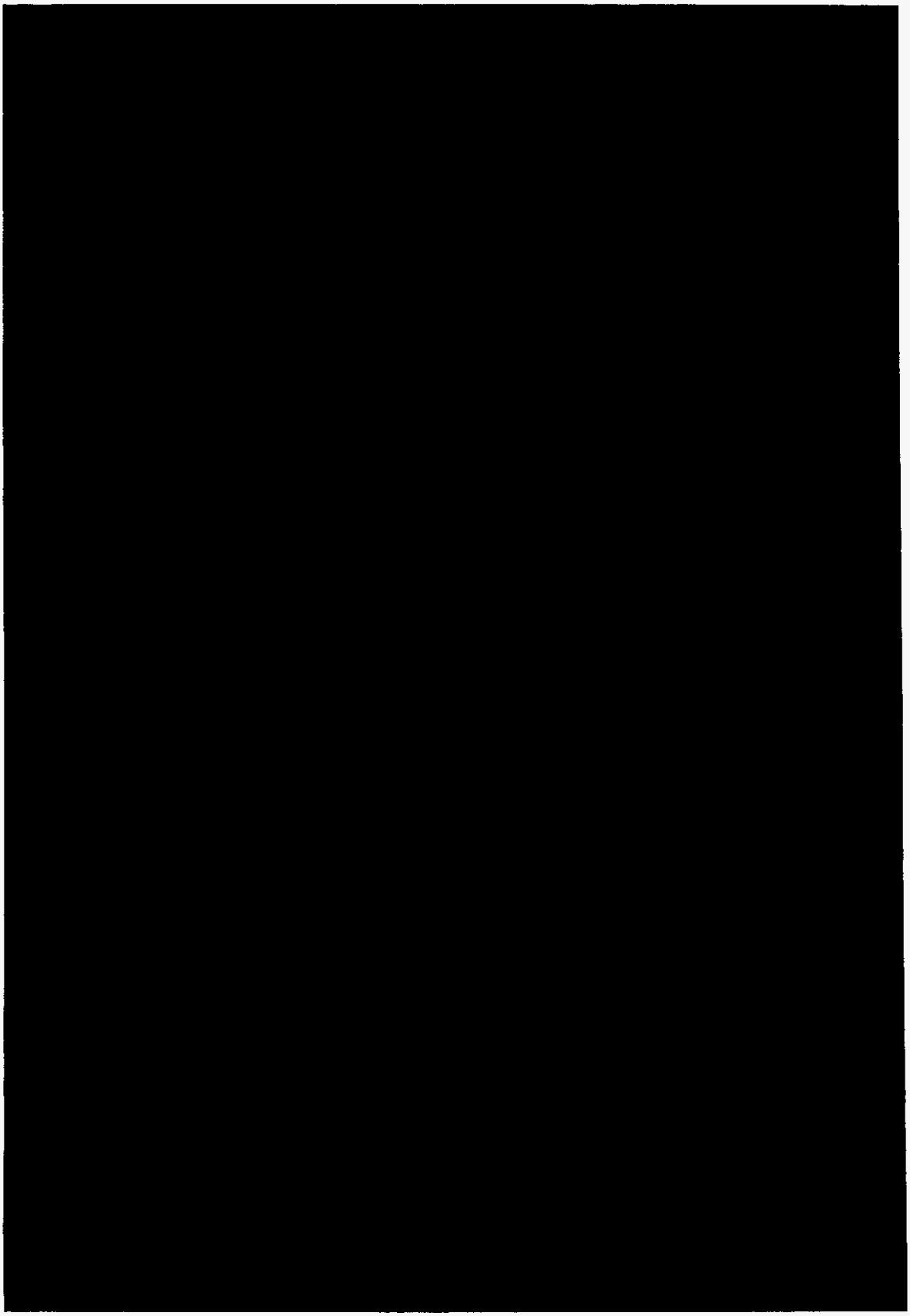
NAME: Terry L. Morrison

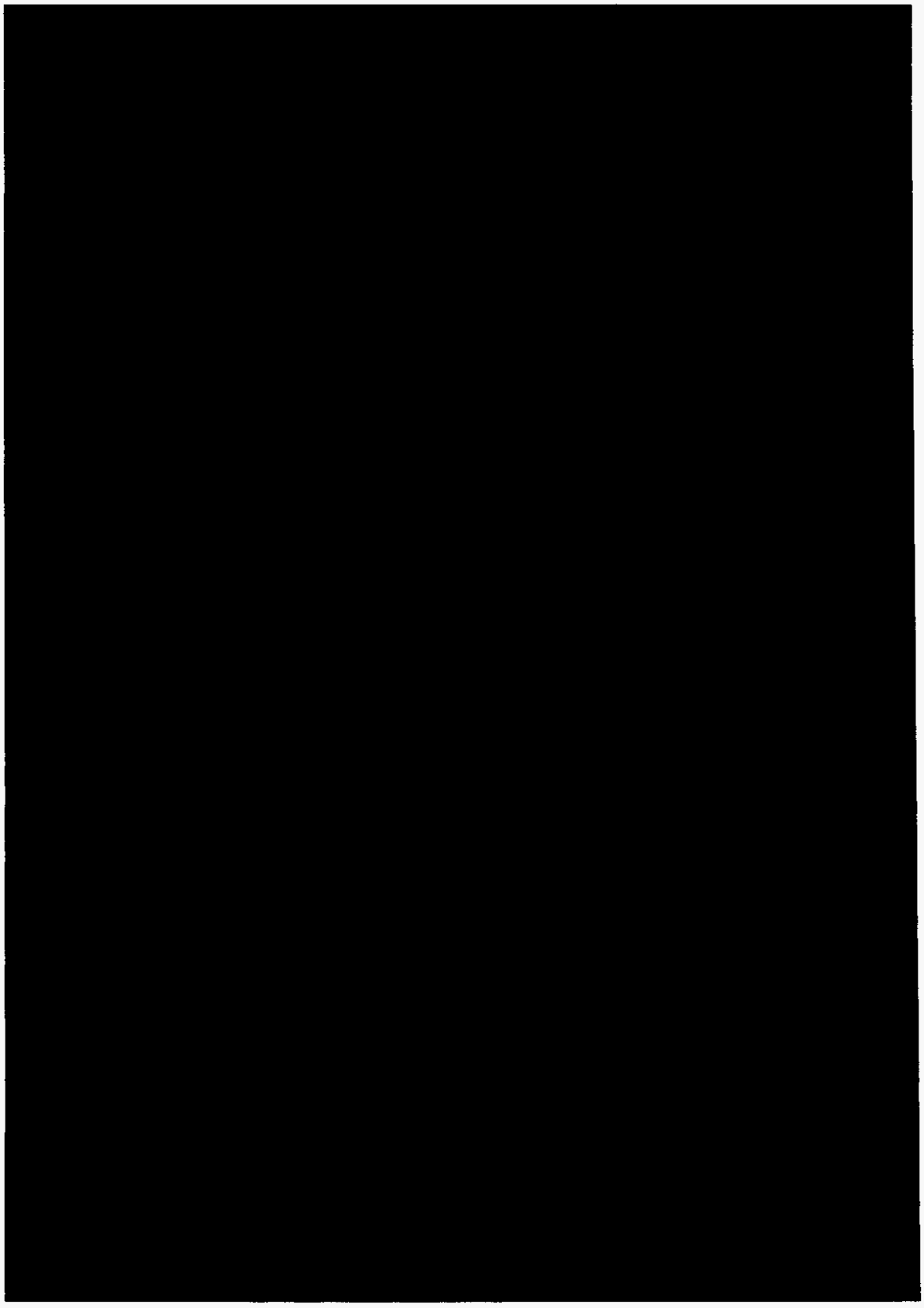
TITLE: Vice President

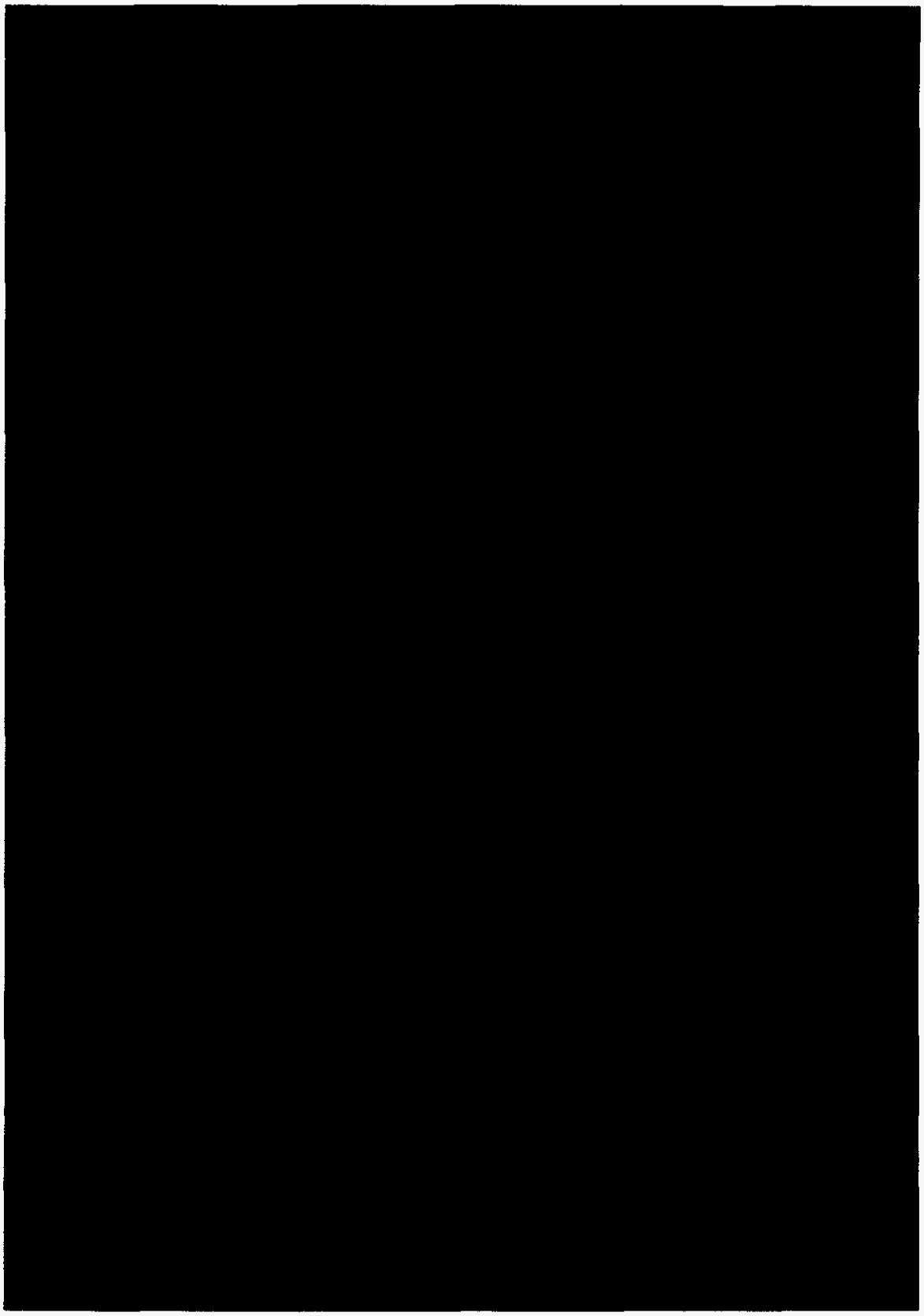


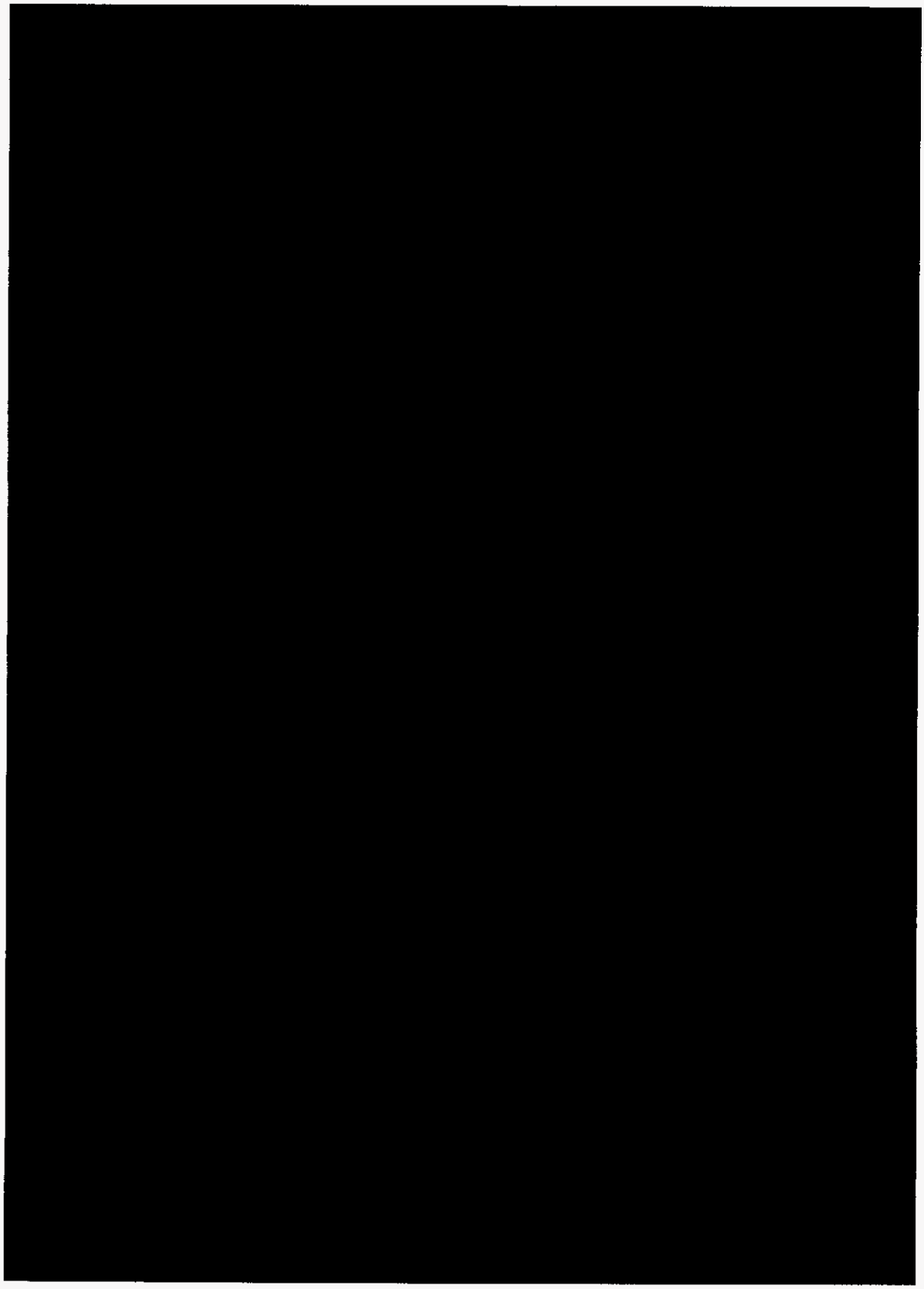


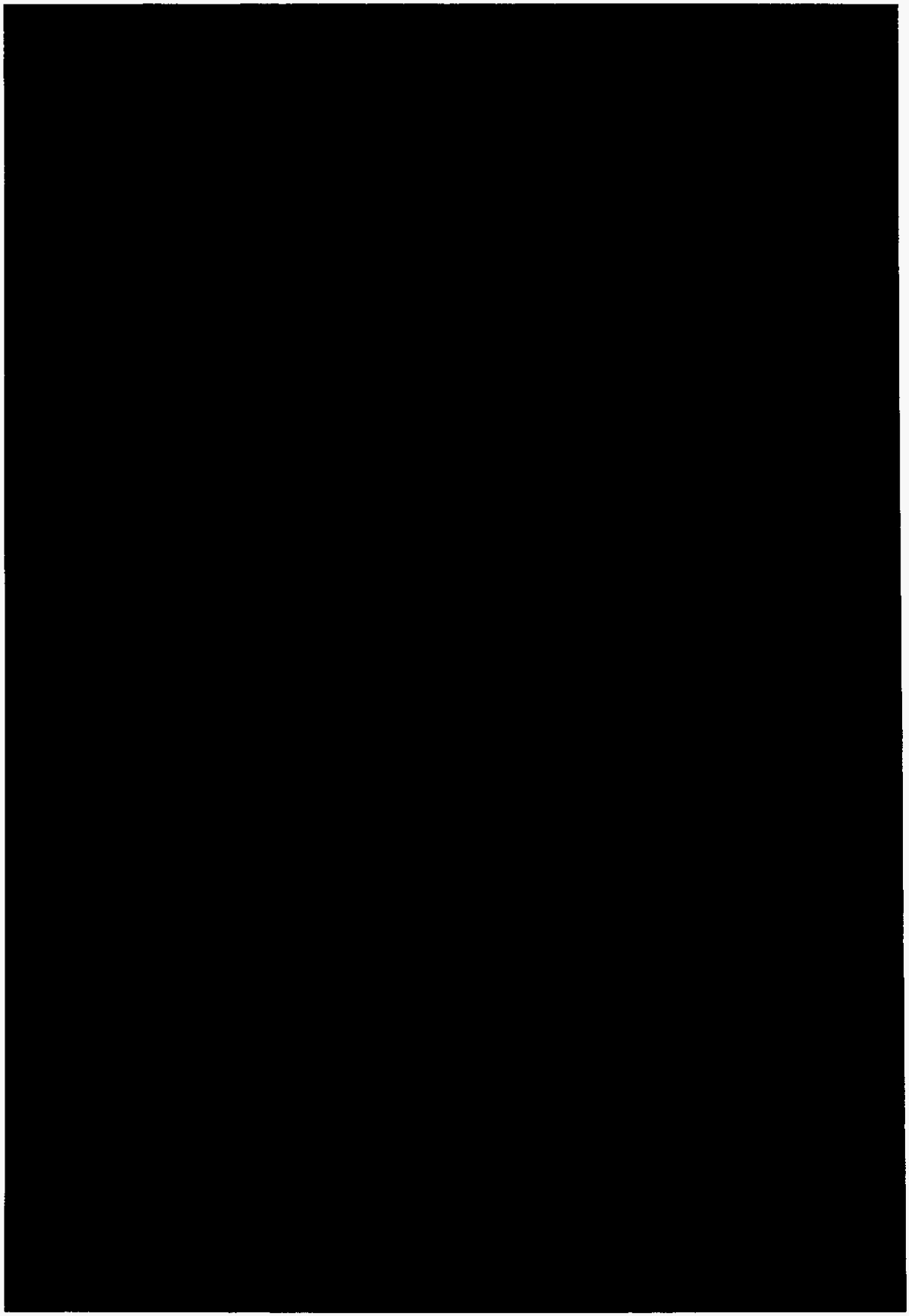


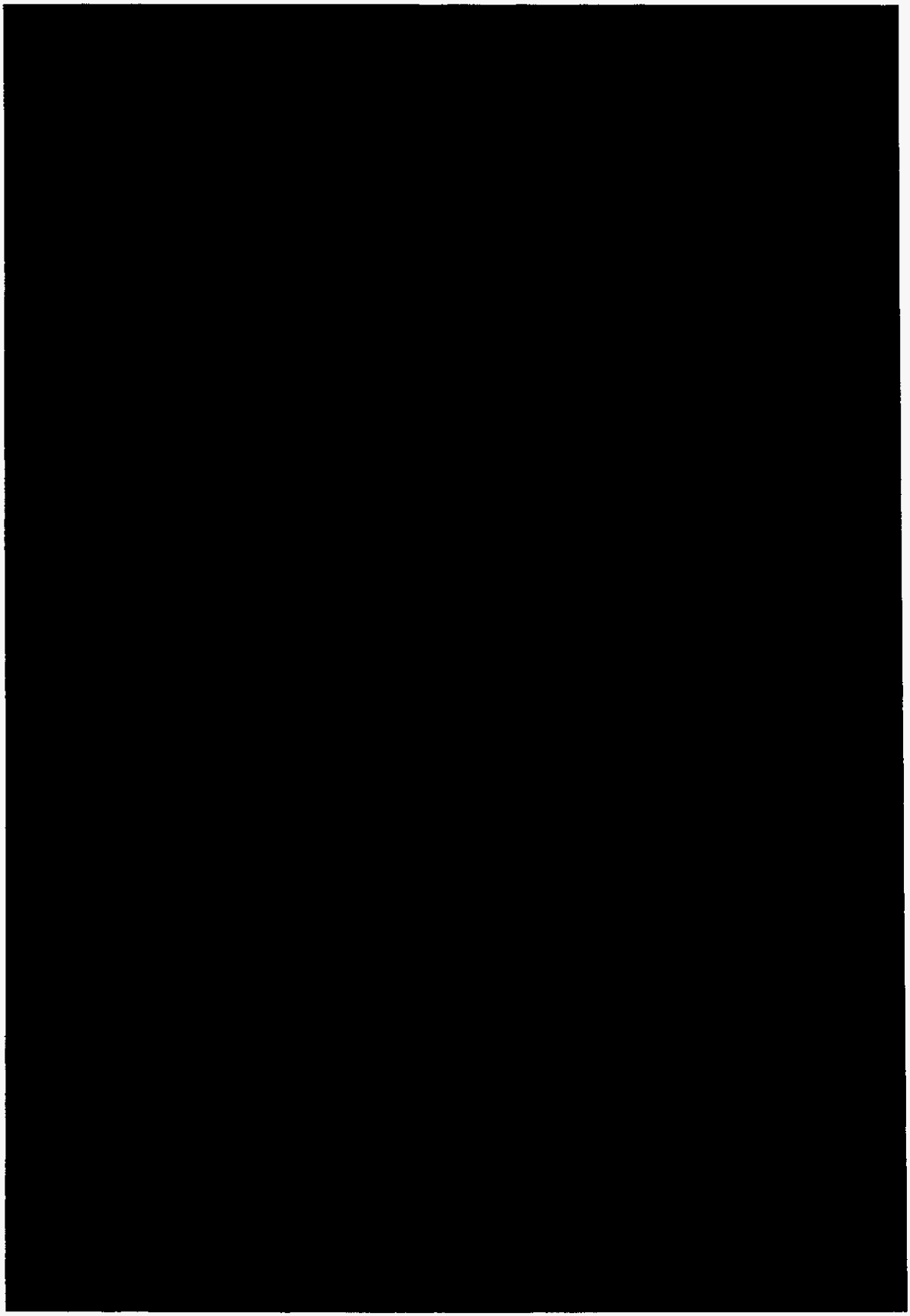


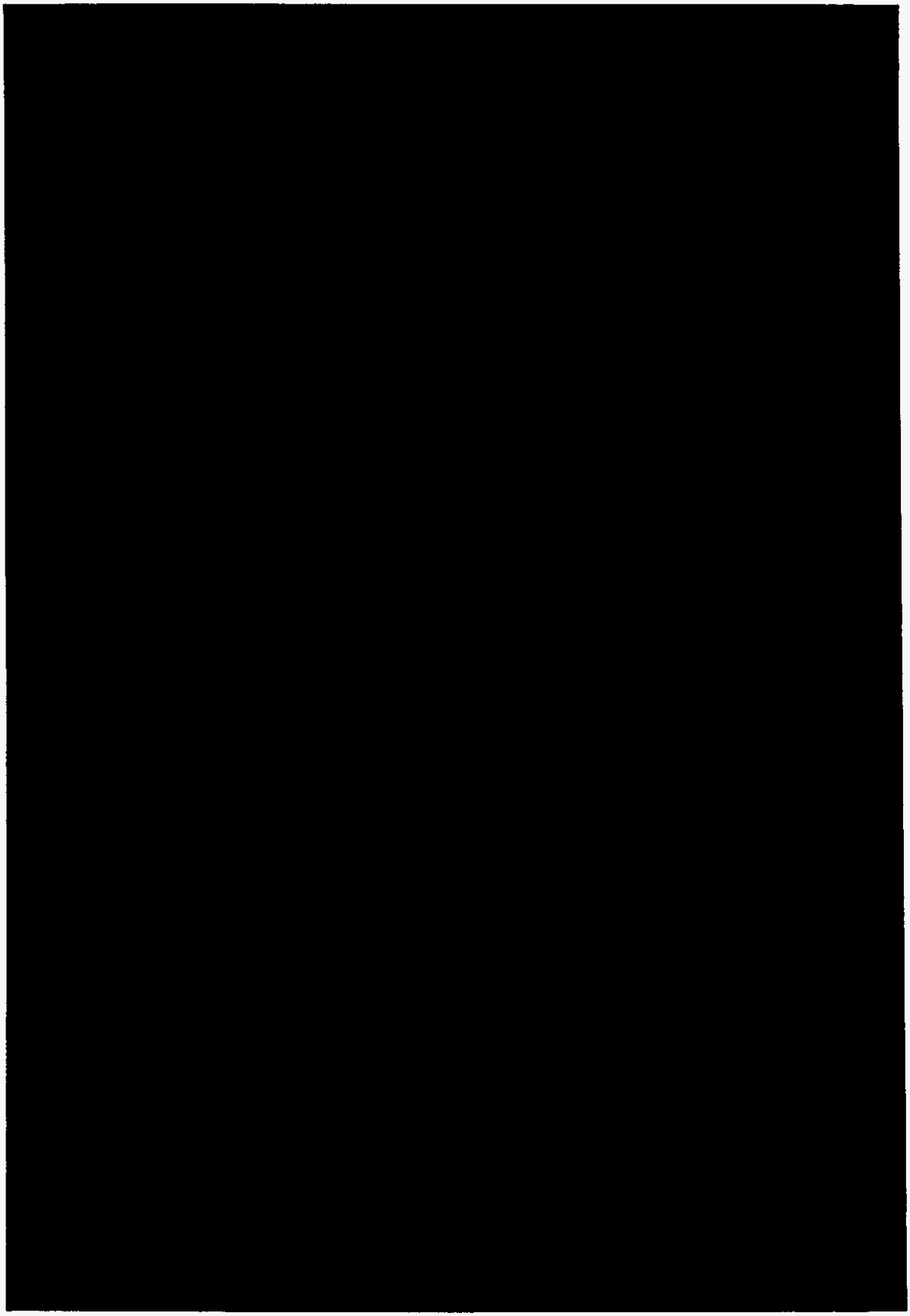


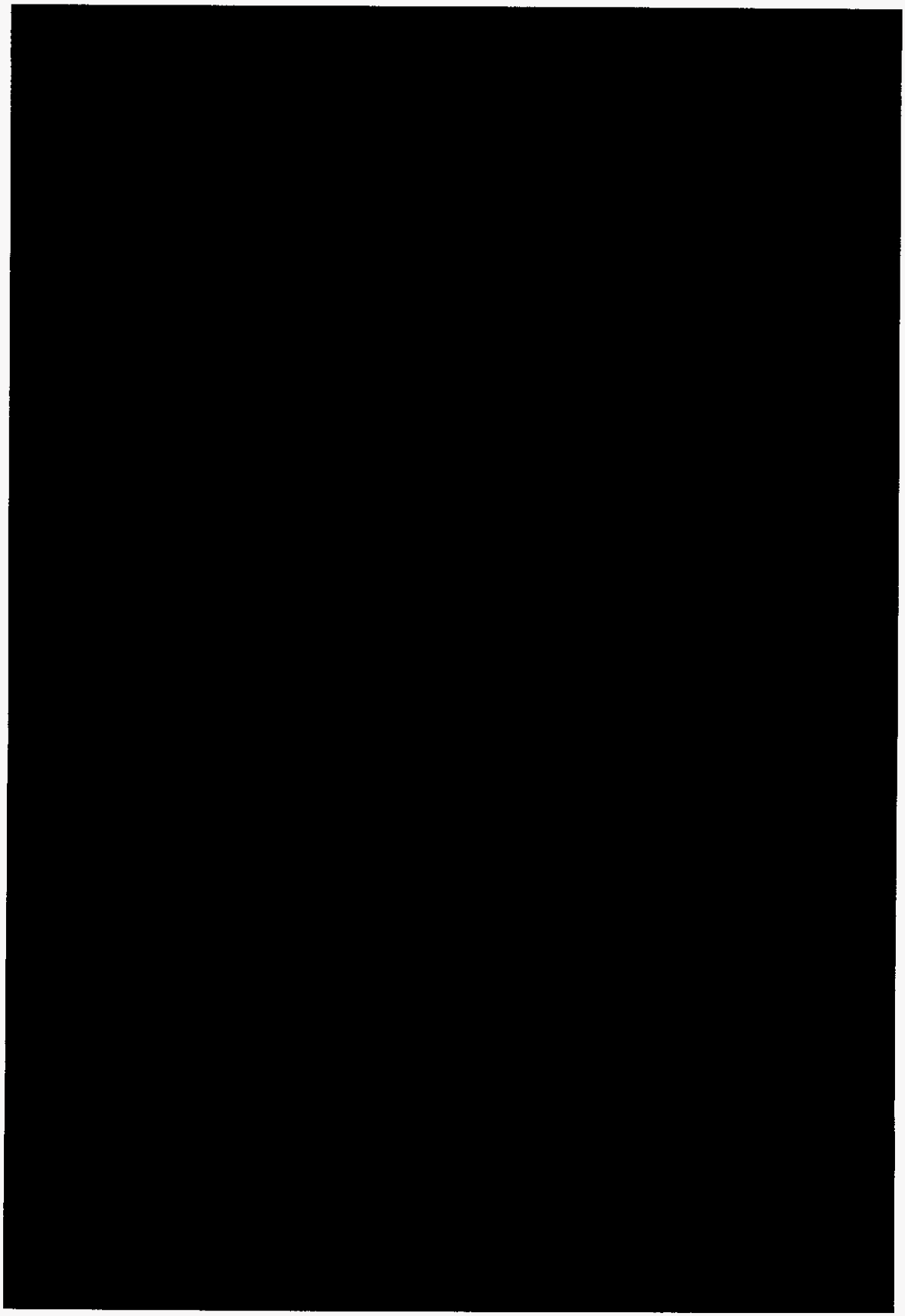


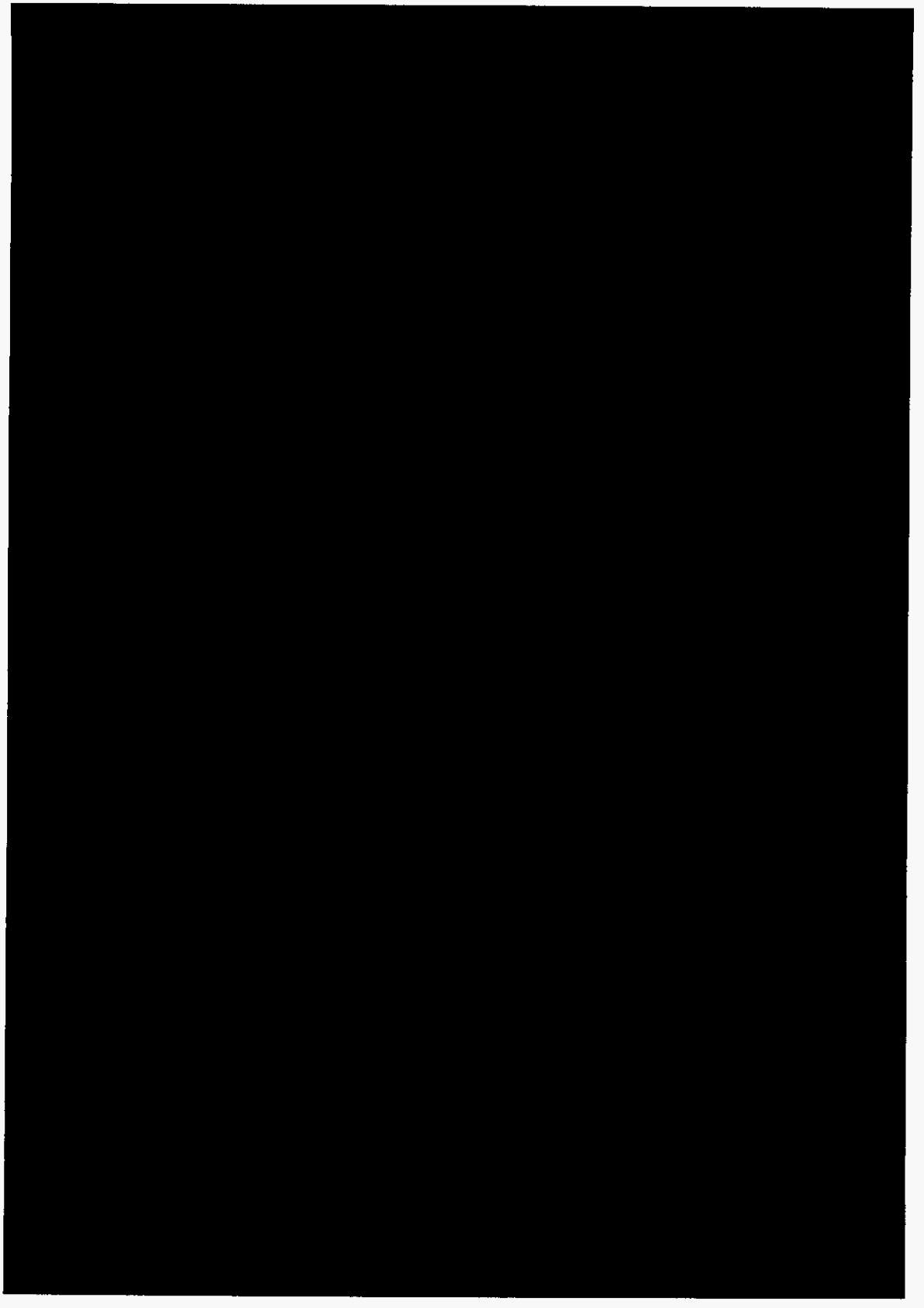


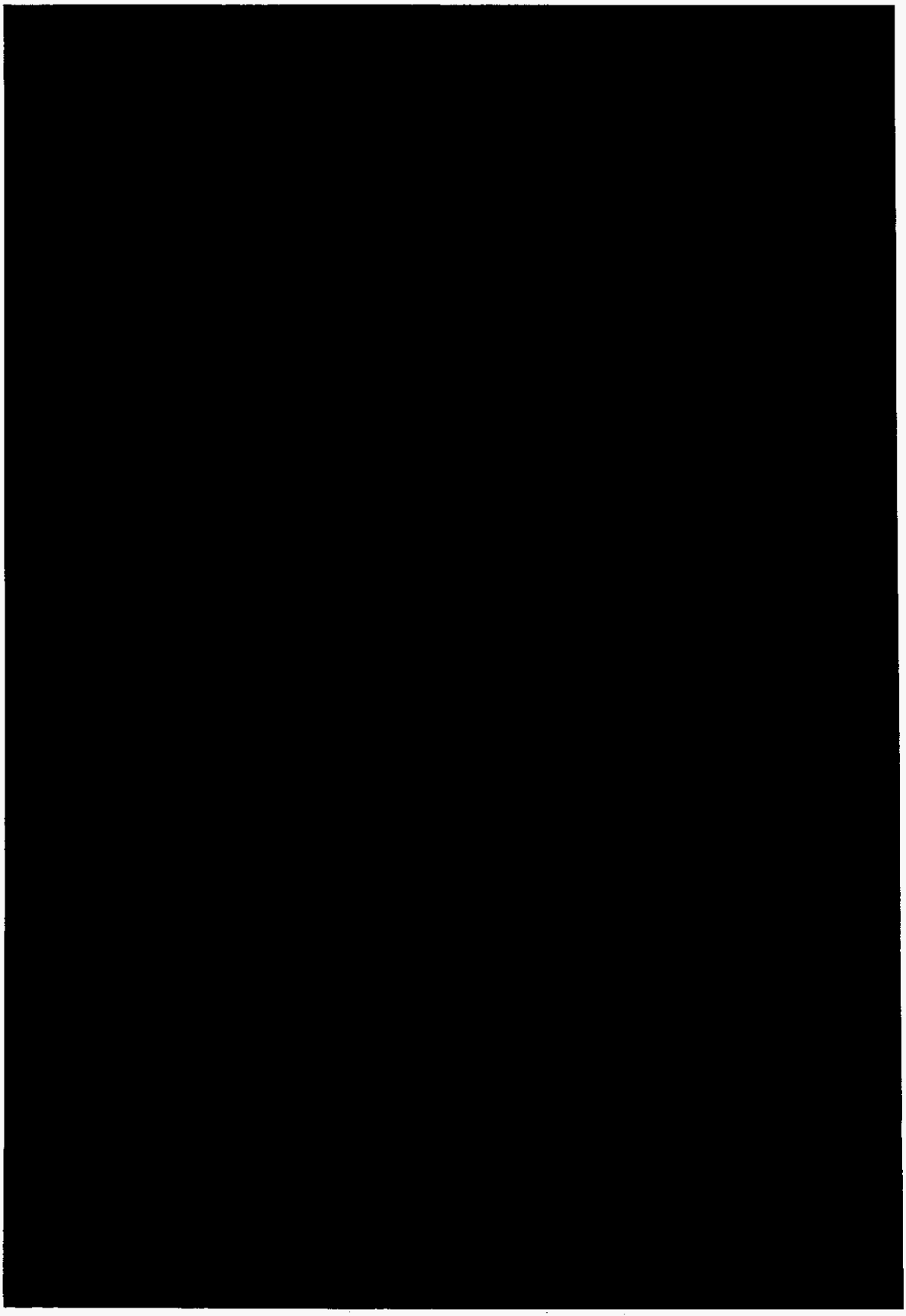


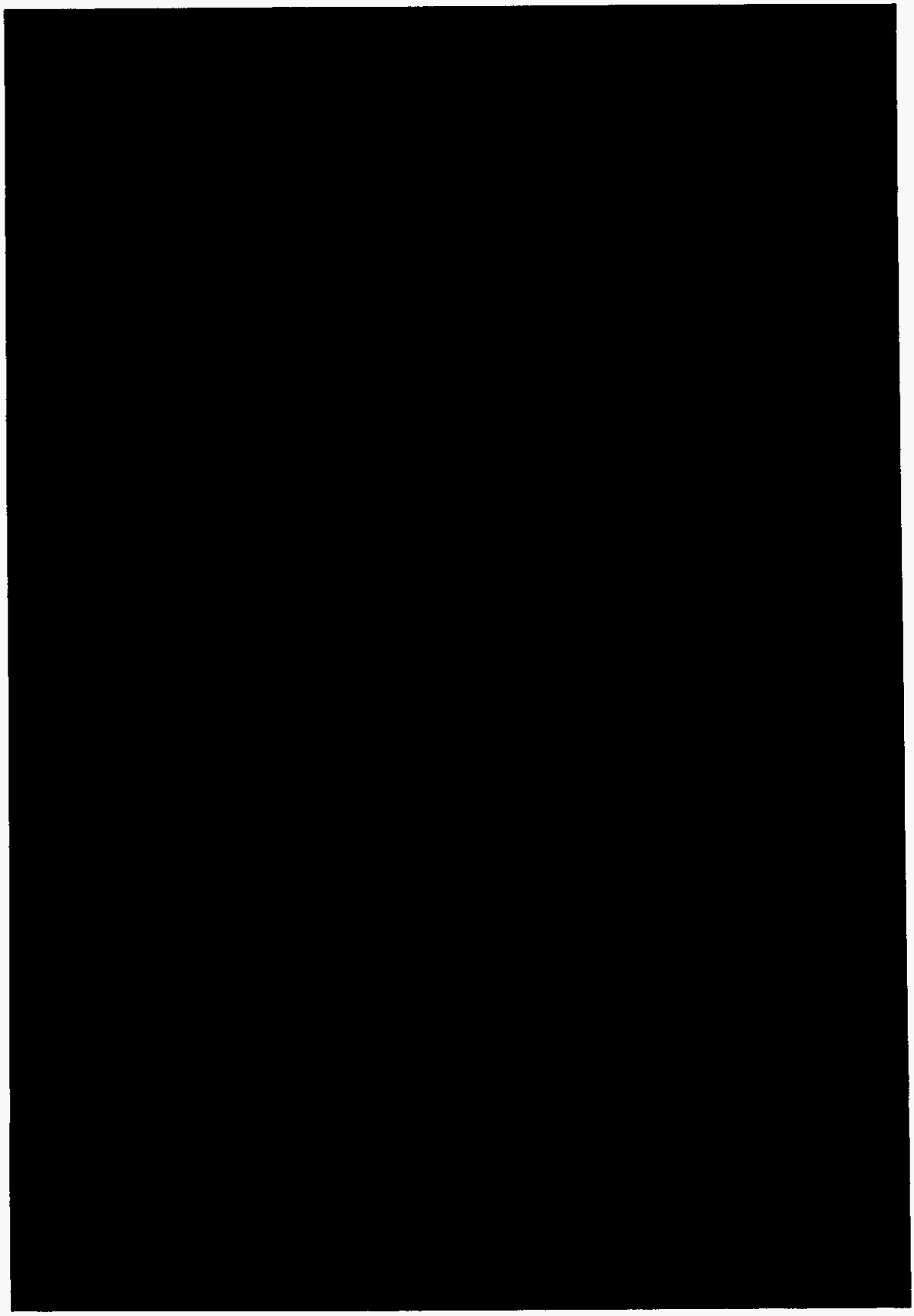


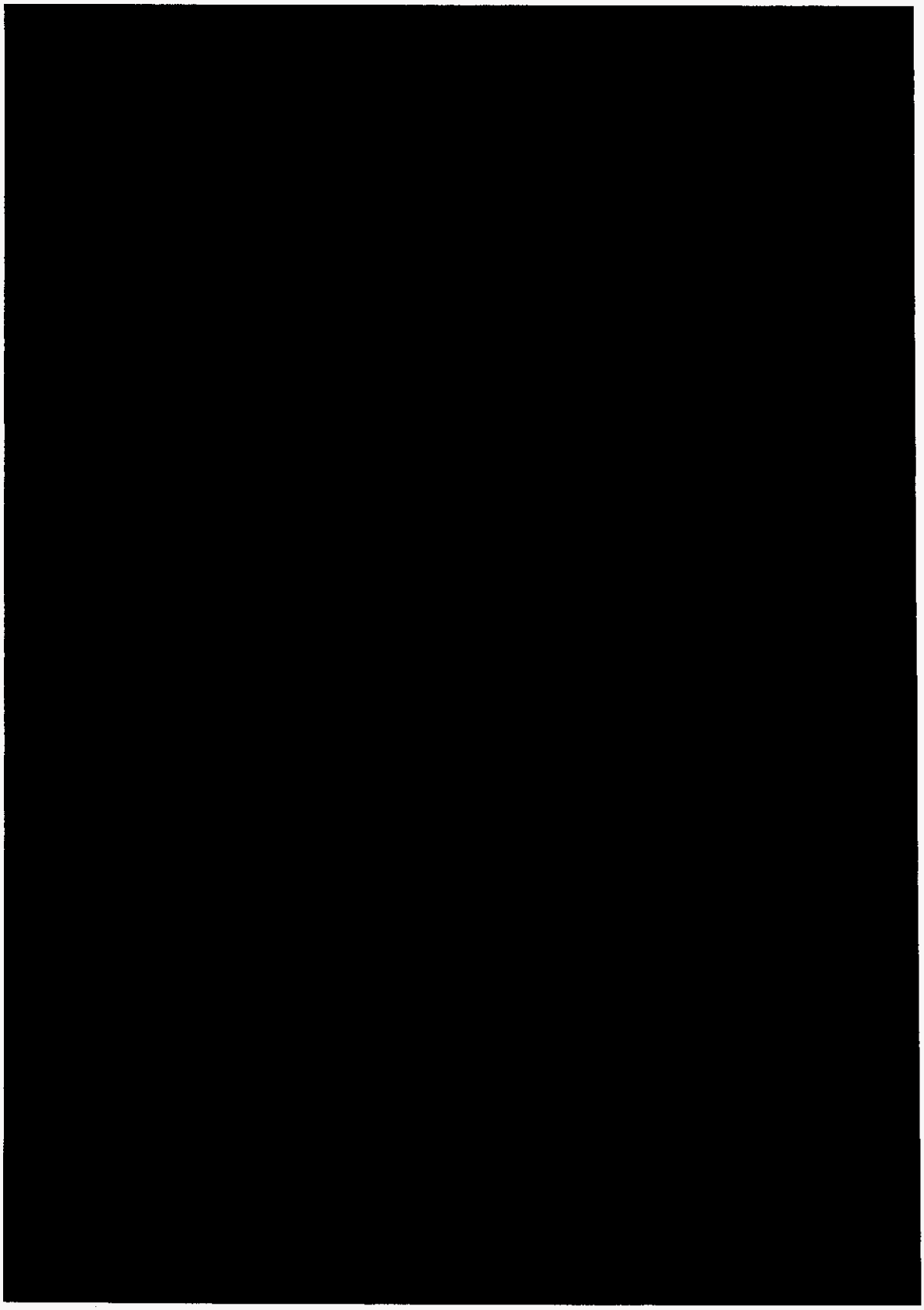


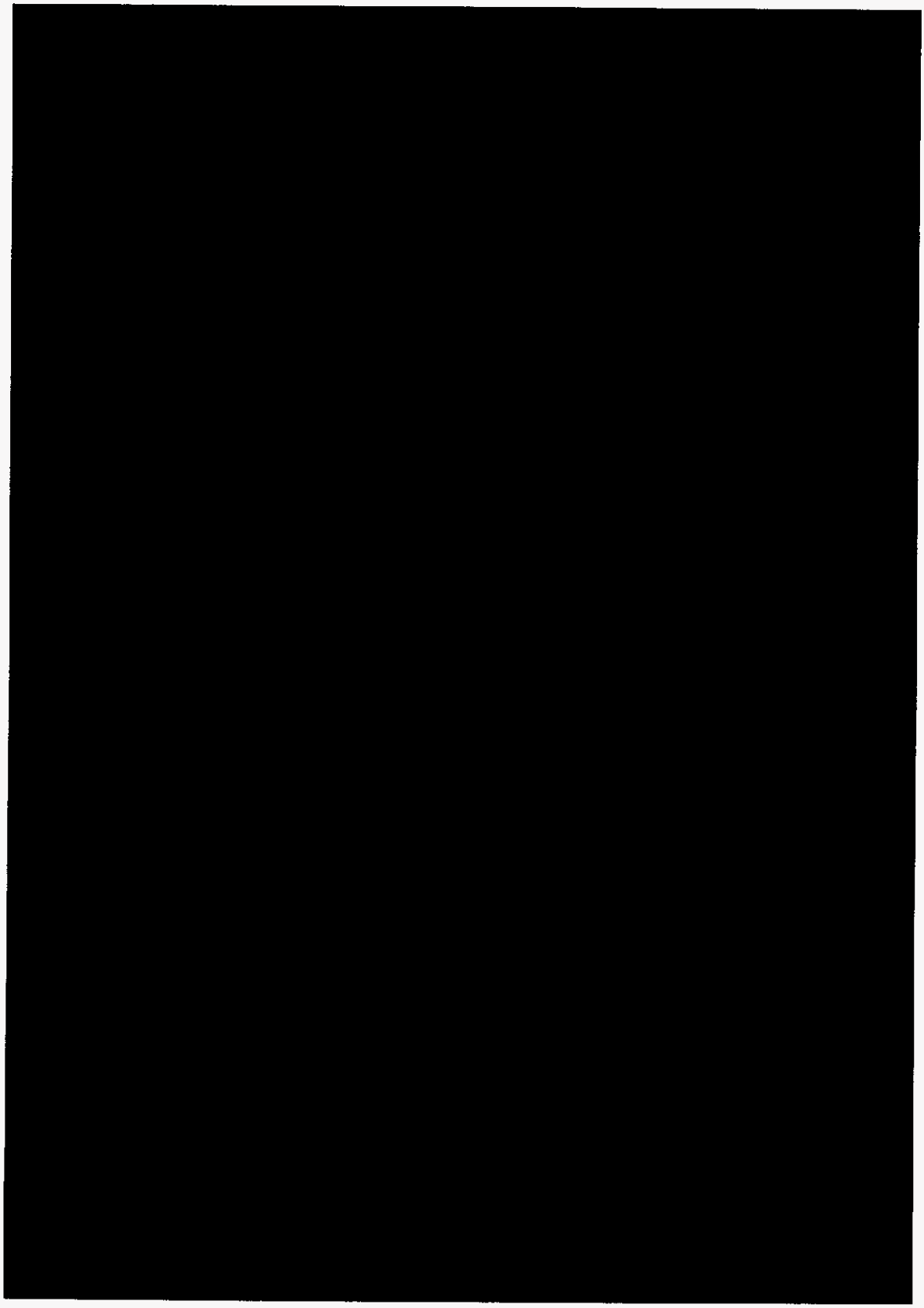


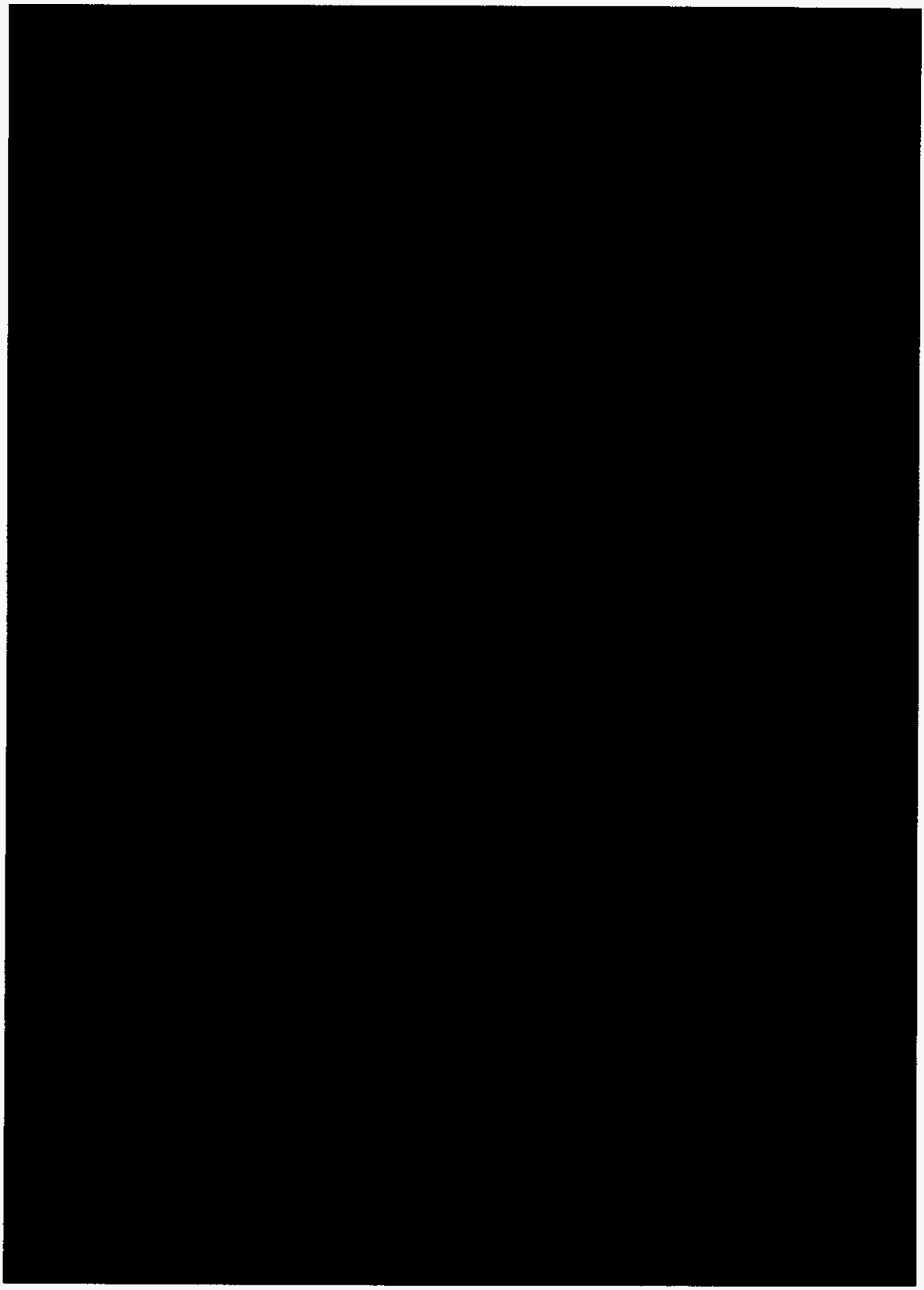


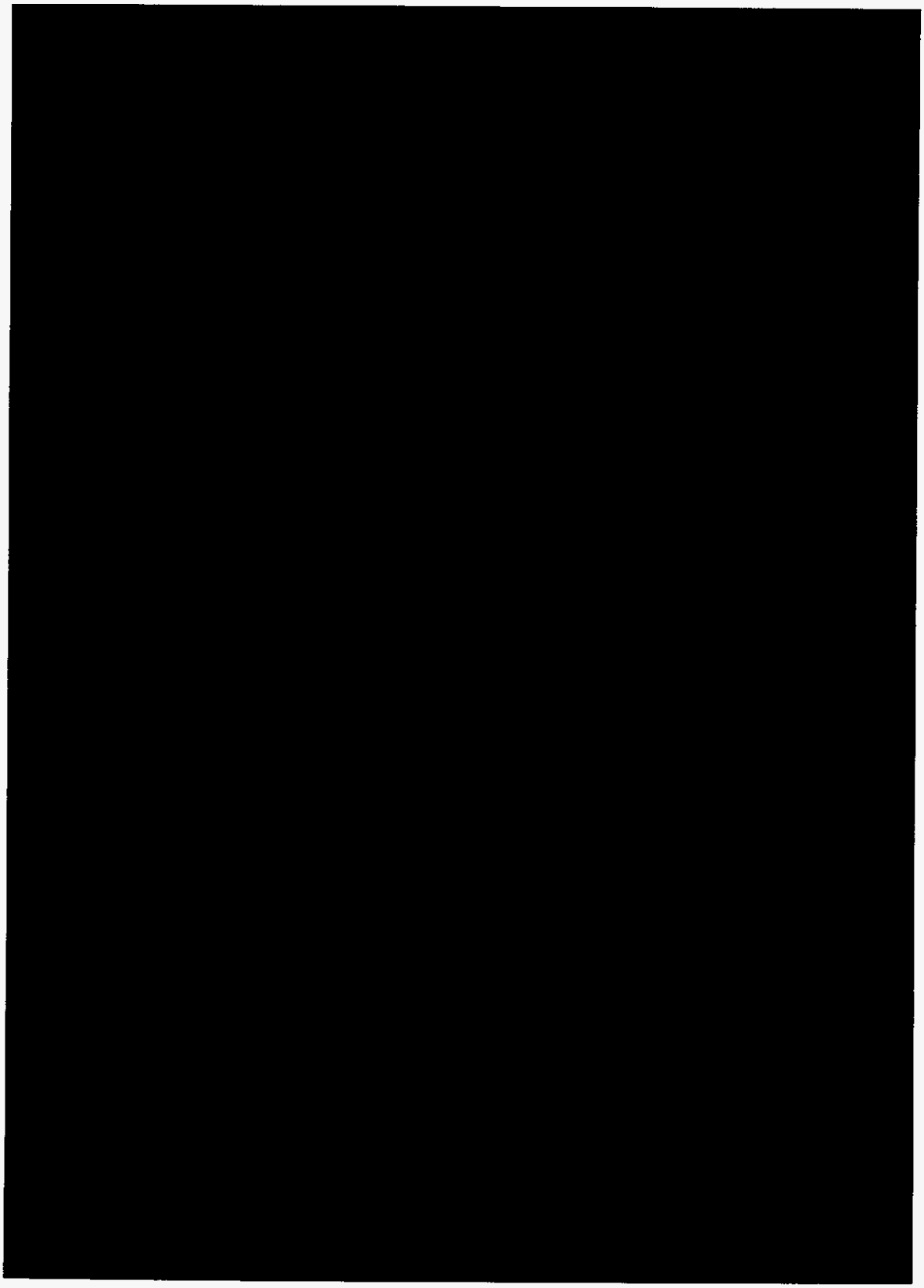


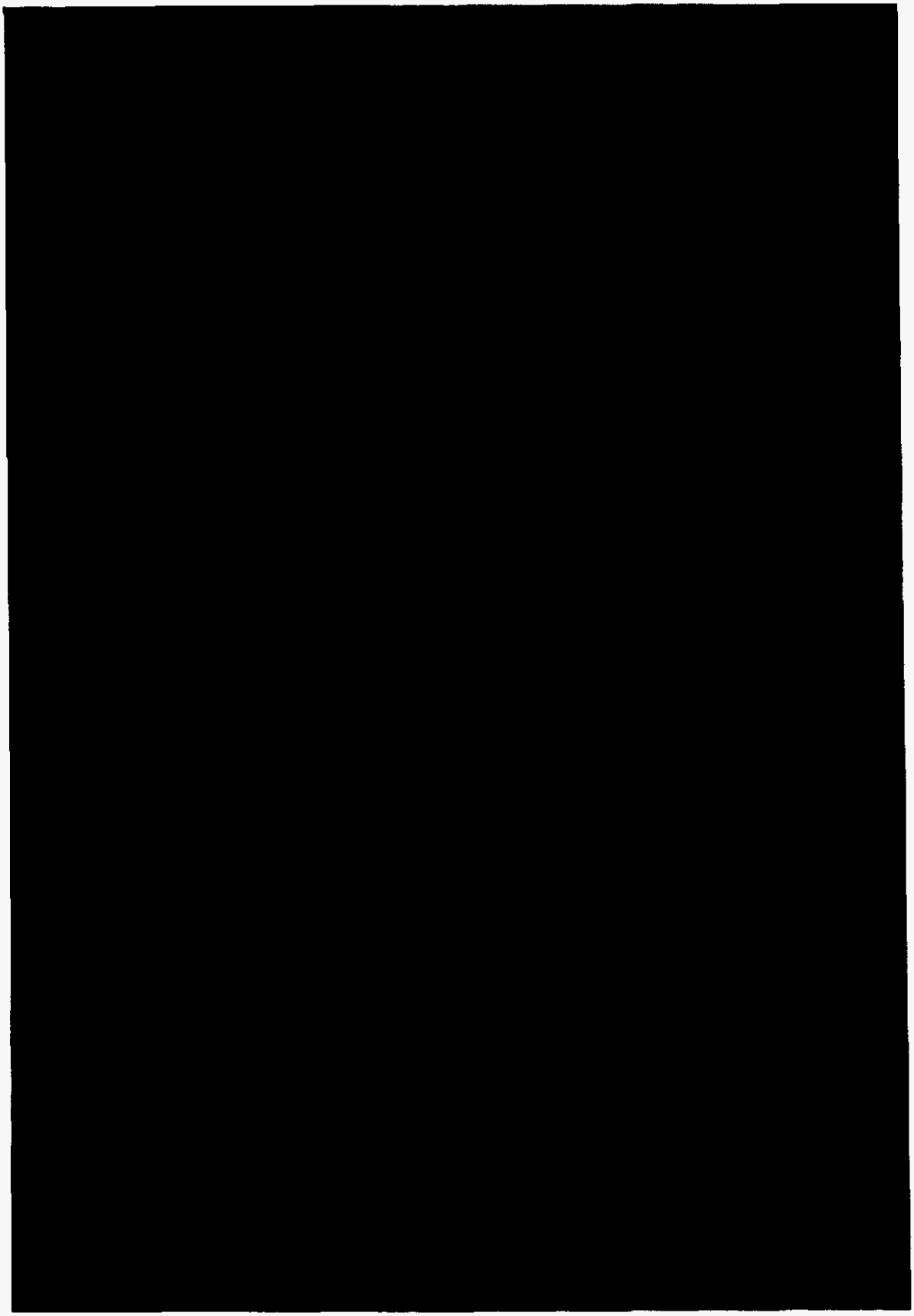


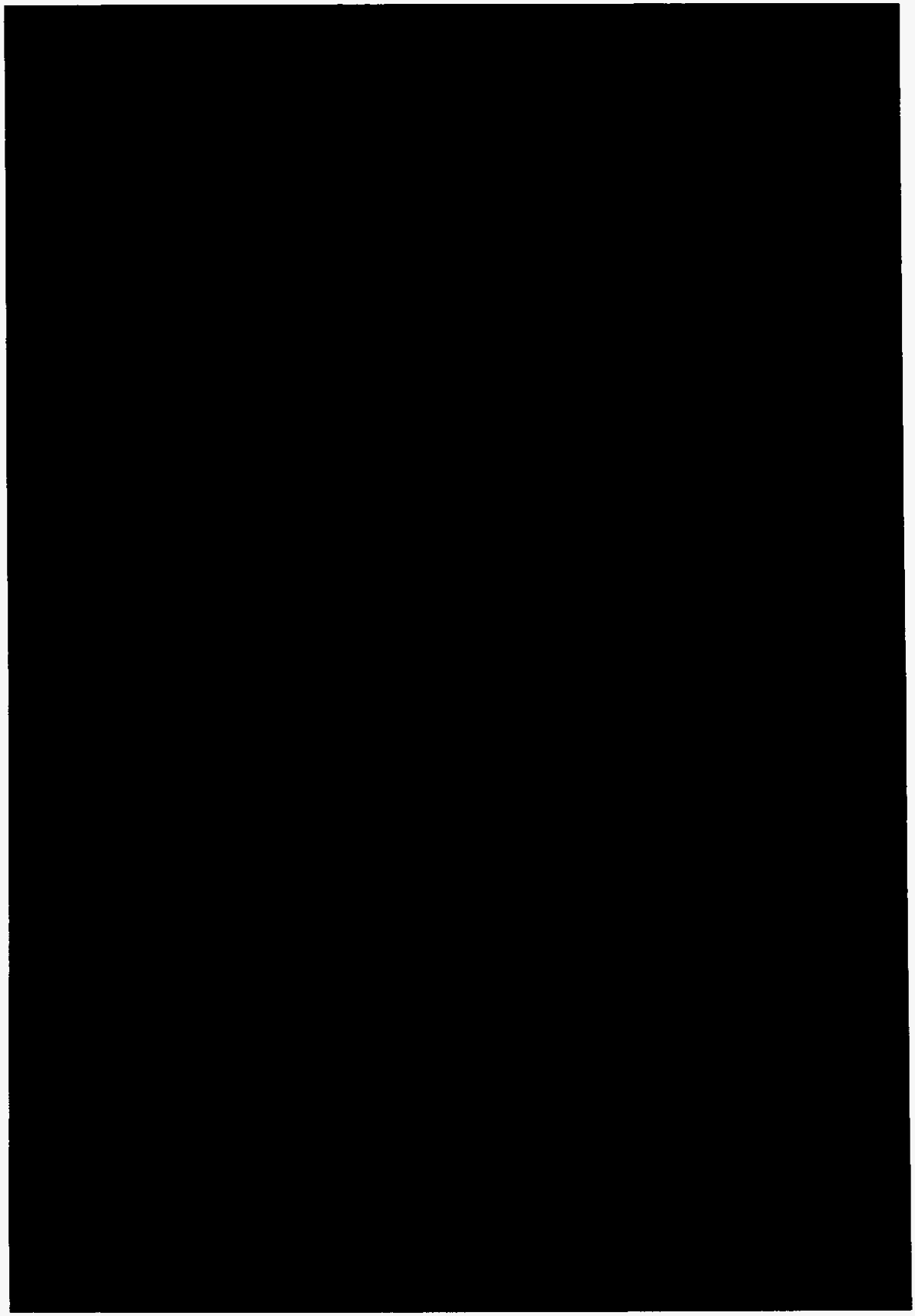


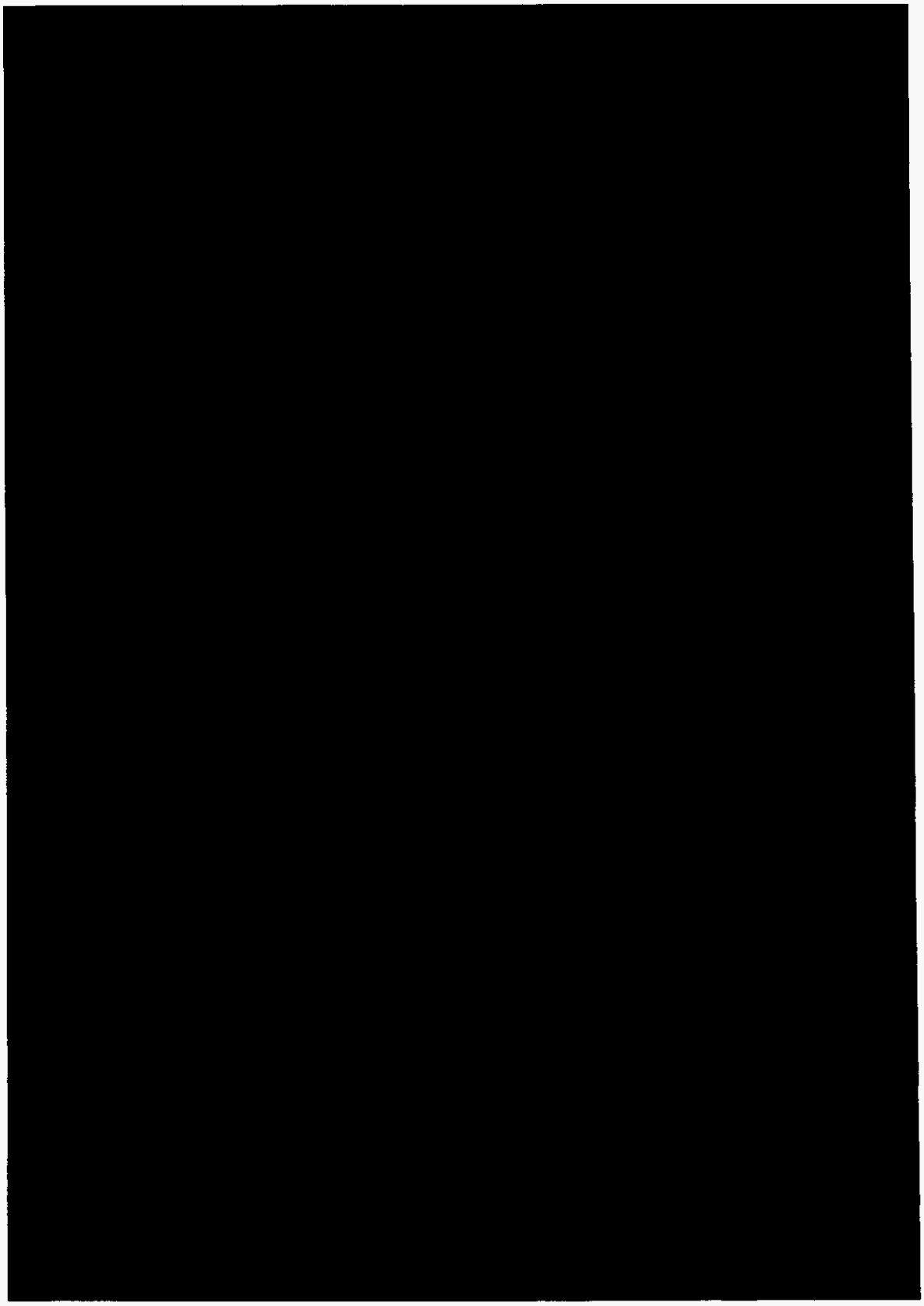


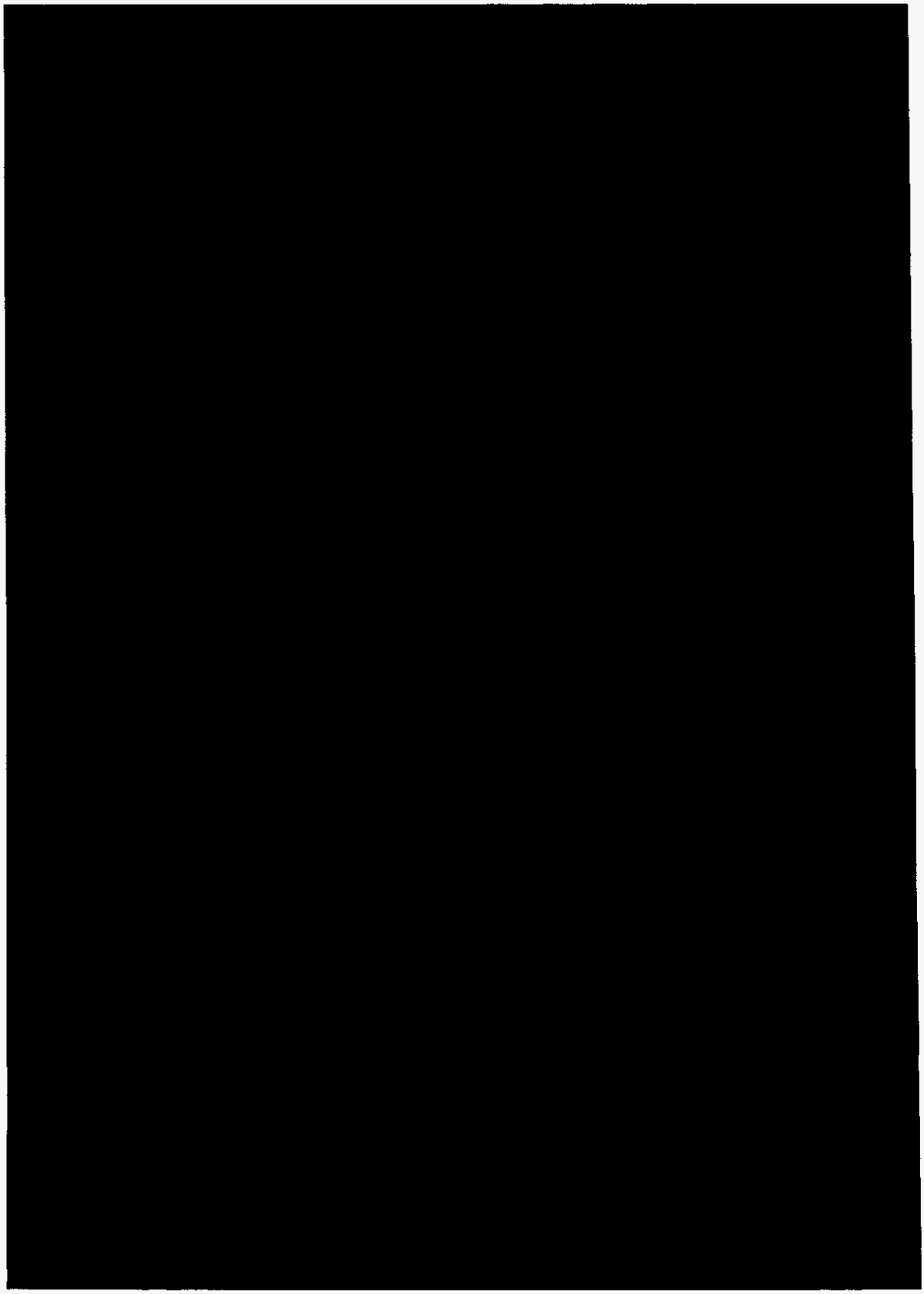


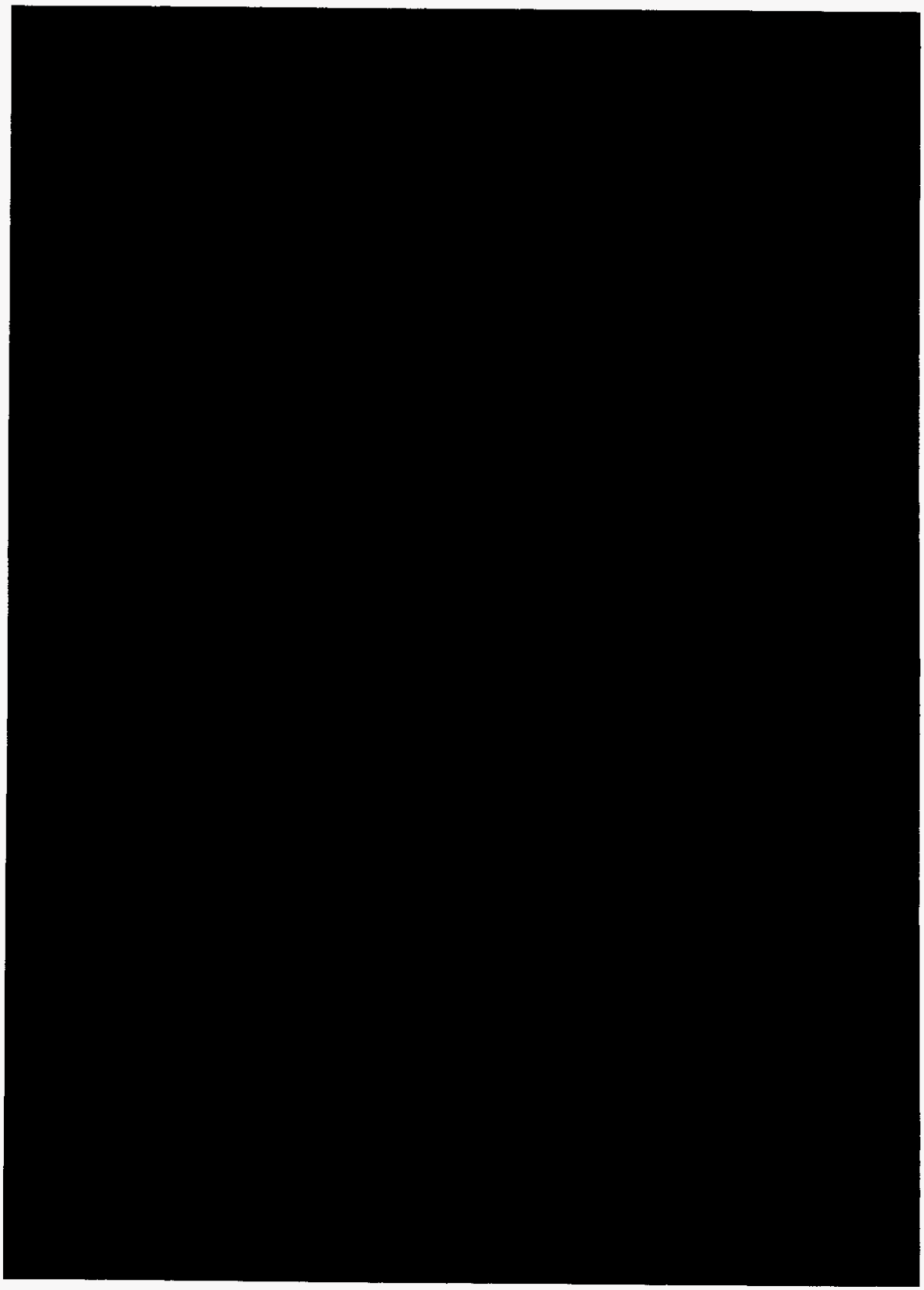












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT HARRIS UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 14
COMPANY/ F.P.+L.
WITNESS: T.L. Hartman
DATE: 11-08-04

TLH-2
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC. AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Southern Power Company, a Delaware corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203 (hereinafter referred to as "Southern Power" or "Seller") and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"1-on-1 Operating Mode" means any time a Schedule requests energy for any hour in an amount between and including [redacted] (whether or not such energy is supplied from an Alternate Resource(s)).

"2-on-1 Operating Mode" means any time a Schedule requests energy for any hour in an amount equal to or greater than [redacted] MW (whether or not such energy is supplied from an Alternate Resource(s)).

"Affiliate" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" means, with respect to any payment under Section 14.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or

the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"Agreement" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"Alternate Delivery Point(s)" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.6 or Section 5.7 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"Alternate Resource(s)" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.6 or Section 5.7.

"Available Capacity" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"Billing Month" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"Btu" means British Thermal Units.

"Business Day" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"Buyer" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Central Prevailing Time" or **"CPT"** means the local time at any point in Birmingham, Alabama.

"Change in Law" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"Commercially Reasonable" or **"Commercially Reasonable Efforts"** means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"Contemporaneous Agreements" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Franklin Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Seller) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Scherer Unit No. 3 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Georgia Power Company and Gulf Power Company) and Buyer.

"Contest" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"Contract Capacity" means the lesser of: (i) 600 MW; or (ii) the Total Facility Capacity, or such other amount as expressly provided in this Agreement.

"Contract Year" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each 12 Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"Day" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"Delivery Day" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"Delivered Energy" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of: (i) energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule (including Ramp Energy provided at the Facility Delivery Point in connection with such Schedule); and (ii) any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"Delivered Energy Credit" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus

the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.6.1 in response to a Force Majeure Event.

"Delivery Excuse" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); (iii) any directive from the applicable transmission provider and/or control area operator to cease deliveries of energy from the Facility; (iv) SNG's failure to schedule or to deliver scheduled quantities of Gas to the Facility (but only if, for the period of such failure, Seller has complied with Section 9.1 and has utilized Commercially Reasonable Efforts to utilize available transportation capacity as required by Section 9.2.1 to satisfy Buyer's Schedule); or (v) a circumstance described in Section 9.2.6 and/or Section 9.3.2.

"Delivery Point" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"Effective Date" has the meaning set forth in the introductory paragraph hereof.

"Electric Metering Equipment" means electric meters and associated equipment, including metering transformers and back-up meters.

"EFMH" or **"Equivalent Force Majeure Hour"** shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.6.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"EUH" or **"Equivalent Unavailable Hour"** shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"Event of Default" has the meaning set forth in Section 16.1.

"Facility" means Seller's Gas fired combined cycle electric generating unit known as Plant Harris Unit No. 1 (as may be modified) and all appurtenant facilities, located near Autaugaville, Alabama which directly interconnects to the Southern Company Transmission System.

"Facility Delivery Point" means the substation where the Facility interconnects to the Southern Company Transmission System (or other applicable transmission system) at the transmission system voltage.

"FERC" means the Federal Energy Regulatory Commission, or any successor to its functions.

"Florida Interface" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"Force Majeure Capacity" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Force Majeure Event. Force Majeure Capacity shall be calculated as follows:

Force Majeure Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = the lesser of TCUFM or 600 MW

TCUFM = Total Capacity Unaffected by Force Majeure = Total Facility Capacity – TAC

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Force Majeure Event.

"Force Majeure Event" has the meaning set forth in Section 15.1.

"Gas" means natural gas.

"Government Agency" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"Guarantor" has the meaning set forth in Section 16.1.

"Guaranty" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 20.

"Imaged Agreement" has the meaning set forth in Section 21.17.

"Increased Generation Costs" [redacted]

[redacted]

"kW" means kilowatt(s).

"kWh" means kilowatt hour(s).

"Law" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"Maintenance Outage" has the meaning set forth in Section 4.2.

"Major Maintenance" means the performance of a hot gas path inspection for the combustion turbines at the Facility.

"Major Maintenance Off-Peak Performance Period" means any Off-Peak Performance Period in which Major Maintenance occurs.

"MMBtu" means one million Btu.

"Month" means a calendar month.

"Monthly Capacity Payment" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"Monthly Energy Payment" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"Monthly Fuel Transportation Payment" means the payment for fuel transportation to be made by Buyer to Seller pursuant to Section 6.4.

"Monthly Start Payment" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"Moody's" has the meaning set forth in Section 19.1.

"MW" means megawatt(s).

"MWh" means megawatt hour(s).

"NERC" means the North American Electric Reliability Council, or any successor to its functions.

"Normal Off-Peak Performance Period" means any Off-Peak Performance Period in which Major Maintenance does not occur.

"OATT" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Off-Peak Performance Period" means the period of time consisting of all hours during the Months of October, November, December, January, February, March and April in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Off-Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Off-Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Operating Committee" has the meaning set forth in Section 4.5.

"Operating Mode" means either 1-on-1 Operating Mode or 2-on-1 Operating Mode.

"Operating Procedures" has the meaning set forth in Section 4.4.

"Outage" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure and during Scheduled Outages and Maintenance Outages. An Outage does not include those times that the Facility's capability is reduced (in whole or in part)

due to a Force Majeure Event or a Delivery Excuse. In addition, an Outage shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Outage Capacity" means, for any hour in which an Outage occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Outage. Outage Capacity shall be calculated as follows:

Outage Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = the lesser of TCUO or 600 MW

TCUO = Total Capacity Unaffected by Outage = [the sum of: (A) the lesser of: (i) Total Facility Capacity; or (ii) 600 MW; and (B) Unused Excess Capacity] – TAC

Unused Excess Capacity = to the extent it is positive, the difference of TCUFM as determined under the definition of "Force Majeure Capacity" hereunder, less 600 MW.

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Outage.

"Peak Performance Period" means the period of time consisting of all hours during the Months of May, June, July, August and September in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Performance Period" shall mean either a Peak Performance Period or an Off-Peak Performance Period.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Harris located near Autaugaville, Alabama, which currently consists of the Facility and a combined cycle electric generating unit known as Plant Harris Unit No. 2 and all appurtenant facilities, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal*. In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Ramp Energy" has the meaning set forth in Section 5.2.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"S&P" has the meaning set forth in Section 19.1.

"SNG" means Southern Natural Gas Company.

"Schedule" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"Schedule Start" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled (in either 1-on-1 Operating Mode or 2-on-1 Operating Mode).

"Scheduled Energy" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement, including amounts of Ramp Energy Buyer is required to accept and receive hereunder.

"Scheduled Outage" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"Scheduling Parameters" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"Seller" has the meaning set forth in the introductory paragraph hereof.

"Service Commencement Date" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"Southern Company" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"Southern Company Transmission" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"Southern Company Transmission System" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"Southern Power" has the meaning set forth in the introductory paragraph.

"Taxes" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"Term" has the meaning set forth in Section 2.1.

"Total Facility Capacity" means, for each Contract Year, the generating capability of the Facility as declared by Seller under Article 8.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.6.1 in response to the Outage causing Outage Capacity to exist, less the

Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.6.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term"). Provided, however, Buyer shall be entitled to unilaterally extend the Service Term to December 31, 2017 by providing Seller with written notice on or before January 31, 2010. Upon Buyer's providing such notice, the Service Term shall be deemed to be extended through December 31, 2017.

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 Effect of Termination. Subject to the exercise of a non-defaulting Party's rights under Section 16.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and

Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 Sale and Purchase of Capacity. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 Sale and Purchase of Energy. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"); [redacted] Within 30 Days after receiving Seller's proposed schedule for Scheduled Outages, Buyer may request, in writing, that Seller reschedule any such Scheduled Outages.

Following receipt of such request, Seller shall inform Buyer as to whether it can accommodate Buyer's request and, if so, shall further advise Buyer of the good faith estimated costs that will be incurred by Seller in connection with accommodating the request of Buyer to reschedule the Scheduled Outages. Buyer shall then within 14 Days of the receipt of the estimated costs provided by Seller determine whether Seller should reschedule the Scheduled Outages. Without regard to any prior estimate, Buyer shall reimburse Seller for all Commercially Reasonable costs related to such change in schedule if Seller makes such change. While Seller must use Commercially Reasonable Efforts to accommodate a request of Buyer to re-schedule any Scheduled Outages, Seller may elect to decline rescheduling, if, in Seller's Commercially Reasonable judgment, it would cause a failure on the part of Seller to observe Prudent Industry Practices, or if the proposed reschedule would cause Seller to incur costs which Buyer is unwilling to reimburse. Prior to or during any Contract Year, Seller may modify a schedule of Scheduled Outages to reschedule such outages with the prior written consent of Buyer, which consent shall not be unreasonably withheld, conditioned or delayed.

4.2 [redacted]

[redacted]

4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than 6 months before the Service Commencement Date. Such Operating Procedures shall be completed no later than 30 Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, amounts of Ramp Energy to be received by Buyer under Section 5.2, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages, and hours of Delivery Excuse.

4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone) and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

[redacted]

[redacted]

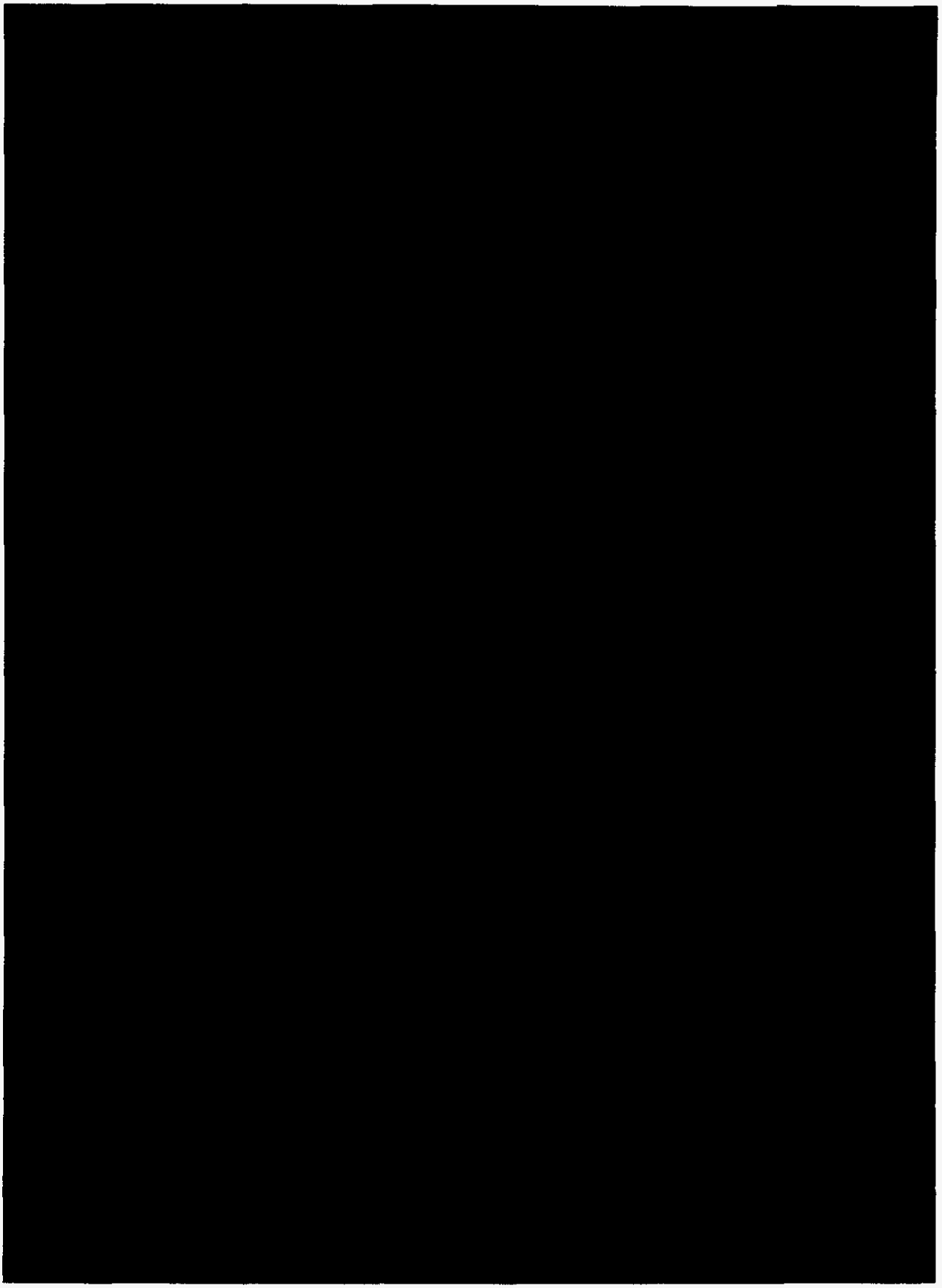
5.2 Ramp Energy. Buyer shall receive and accept at the Facility Delivery Point all energy produced by the Facility during ramping (both starting and shutting down) in connection with satisfying Buyer's Schedule ("Ramp Energy"). The Operating Procedures established pursuant to Section 4.4 shall provide for a procedure whereby Seller, for transmission scheduling purposes, shall provide Buyer with prior notice of the hourly Ramp Energy to be provided for each Schedule. Provided, however, Buyer shall not be required to accept and receive Ramp Energy in an amount greater than [redacted] MWh while the Facility is starting or greater than [redacted] MWh while the Facility is shutting down. For purposes hereof (including Appendix B), Ramp Energy shall be deemed to be Delivered Energy. The Operating Procedures established pursuant to Section 4.4 shall provide for a methodology (consistent with the Facility's manufacturer's recommendations and Prudent Industry Practices) for determining the amounts of Ramp Energy that must be accepted and received by Buyer under this Section 5.2. Ramp Energy shall not be provided to the extent energy is supplied to Buyer from an Alternate Resource(s).

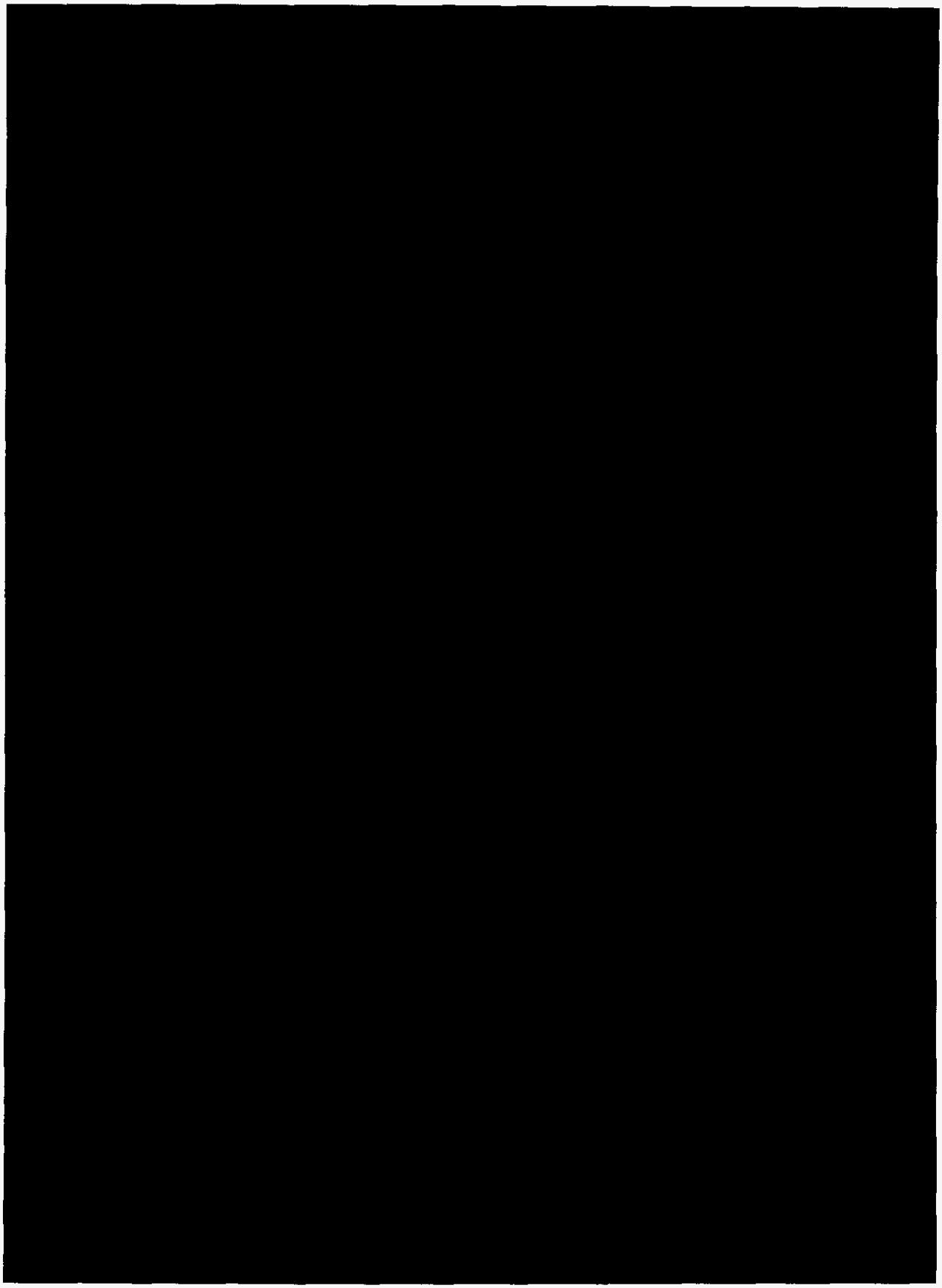
5.3 Transmission and Scheduling Requirements. Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

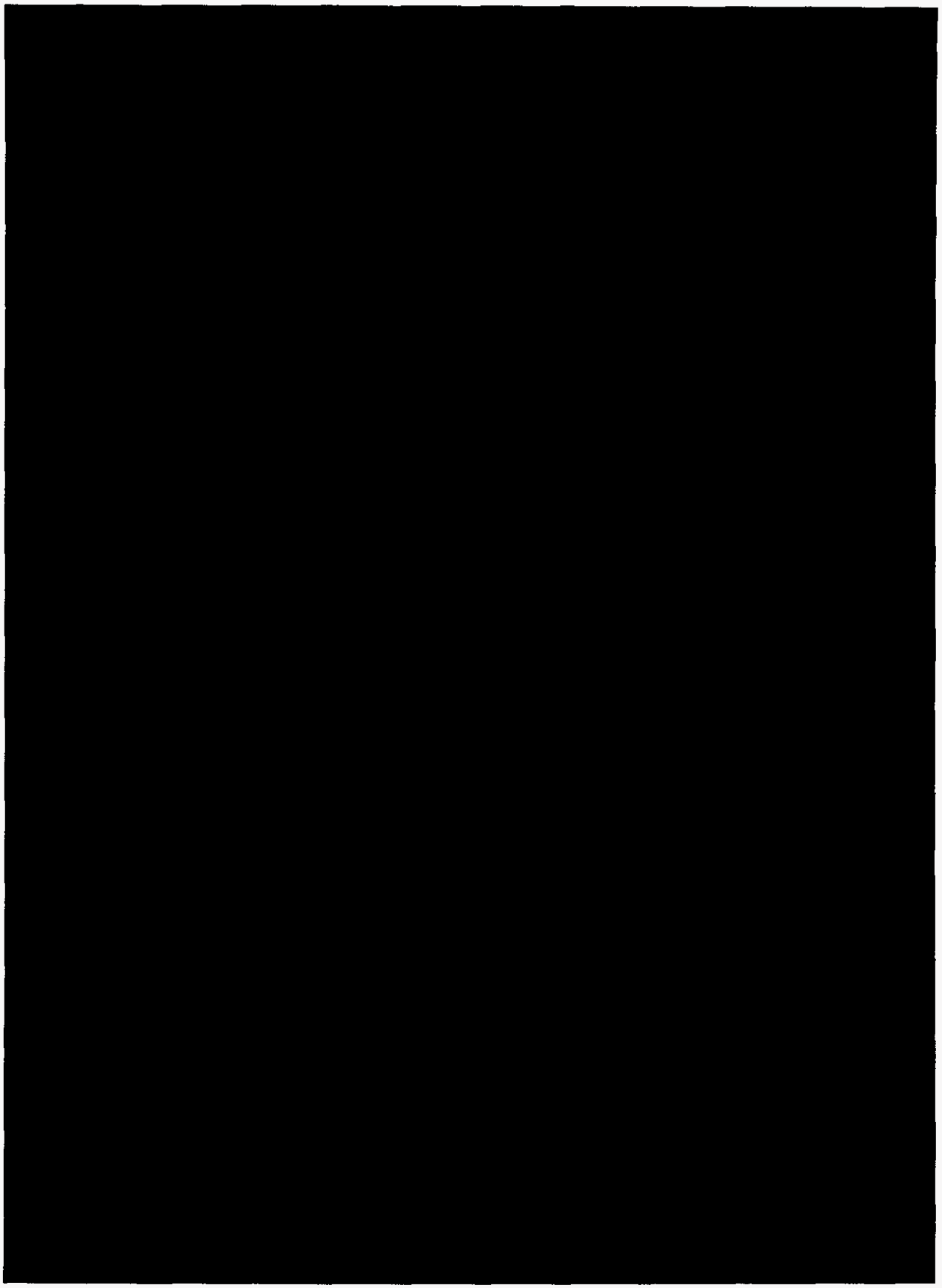
5.4 Costs and Expenses. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

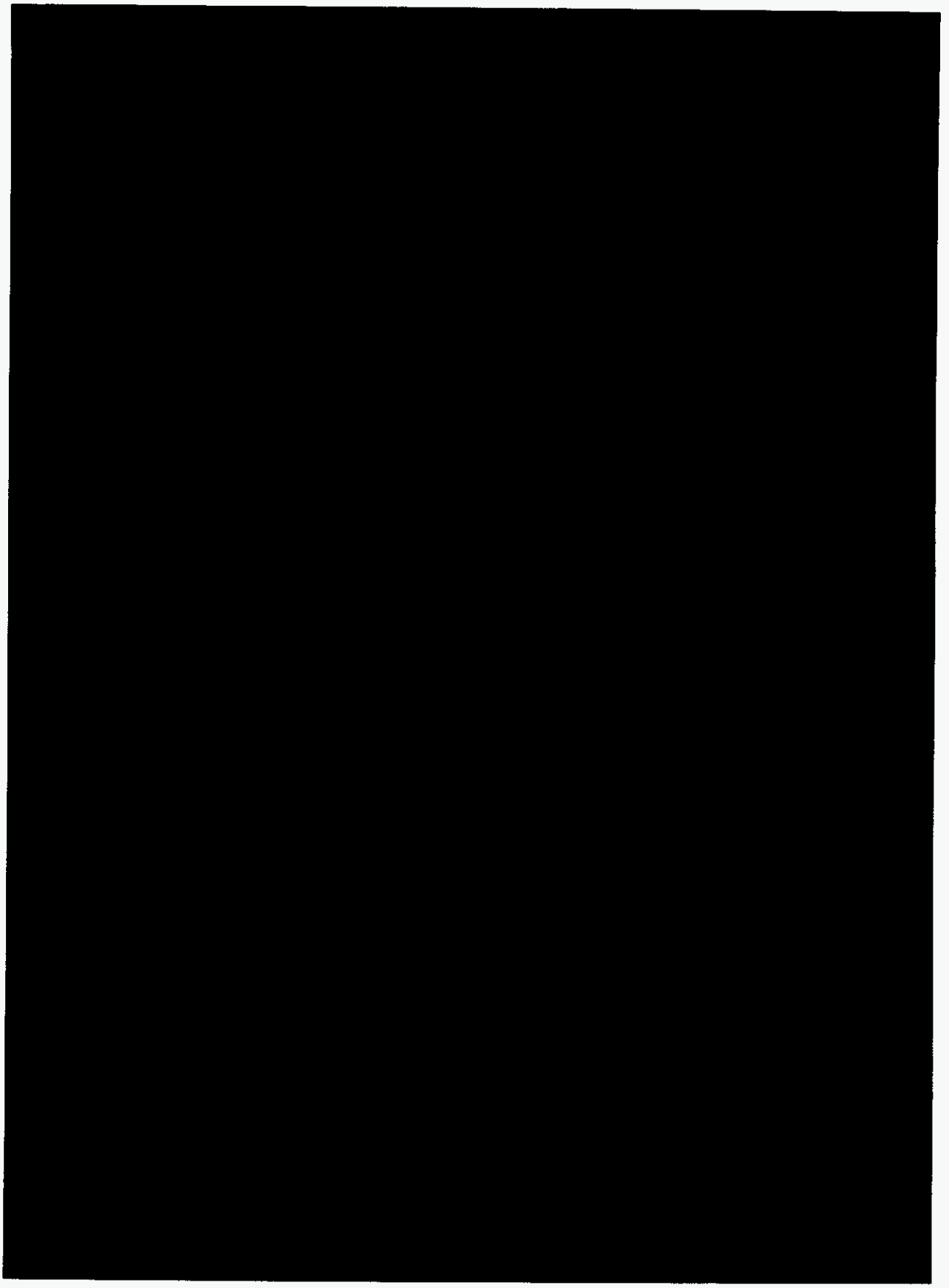
5.5 Delivery of Energy. Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.6 [redacted]









[redacted]

5.8 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.9 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.10 Force Majeure Event.

5.10.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the

extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.6 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.10.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.11 Outages and Unavailable Capacity.

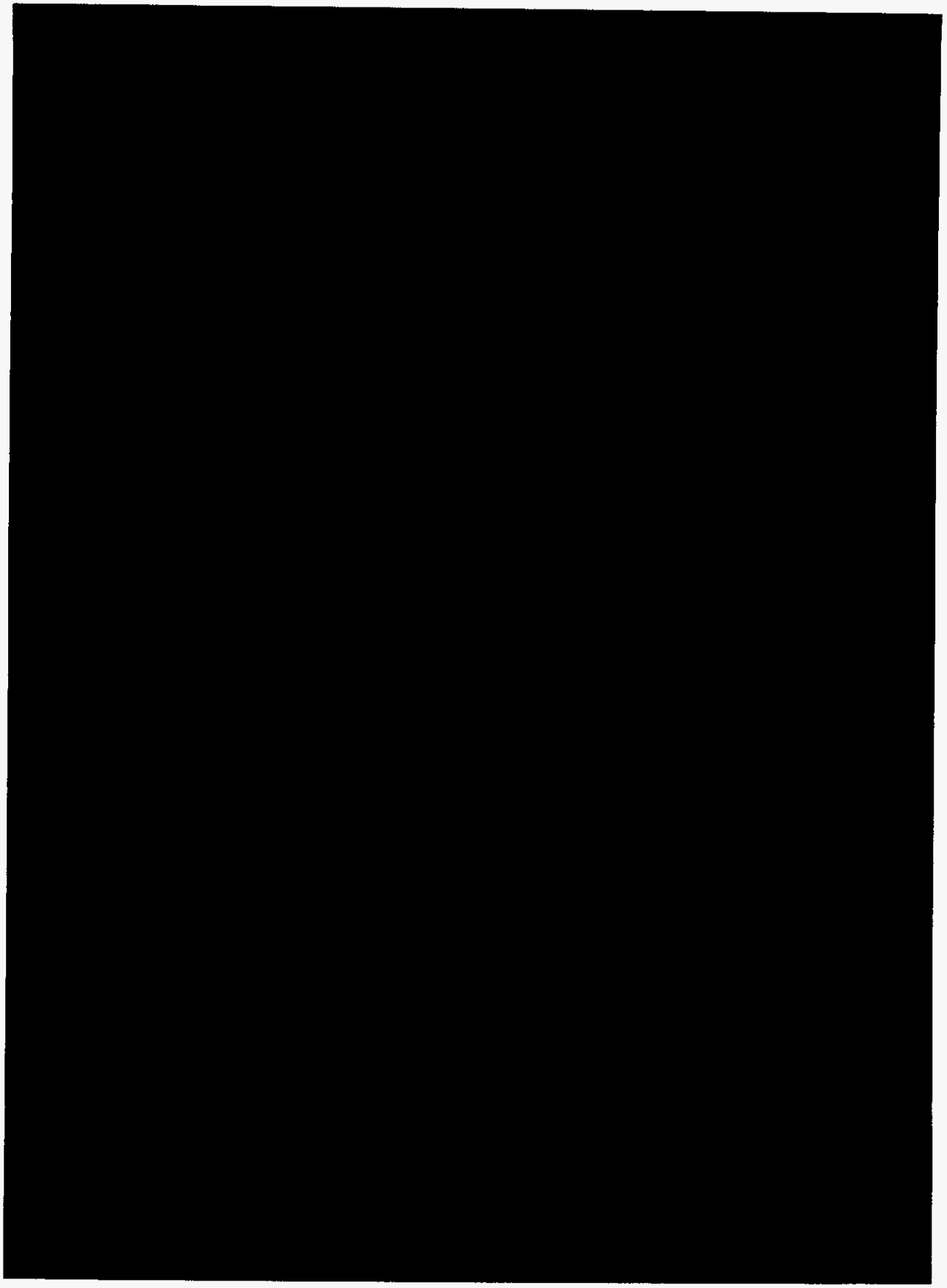
5.11.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Outage that is expected to result in Outage Capacity and the estimated duration of such Outage; (ii) the cessation of such Outage; and (iii) if requested by Buyer within 30 Days after the Outage and if known to Seller, the cause of such Outage.

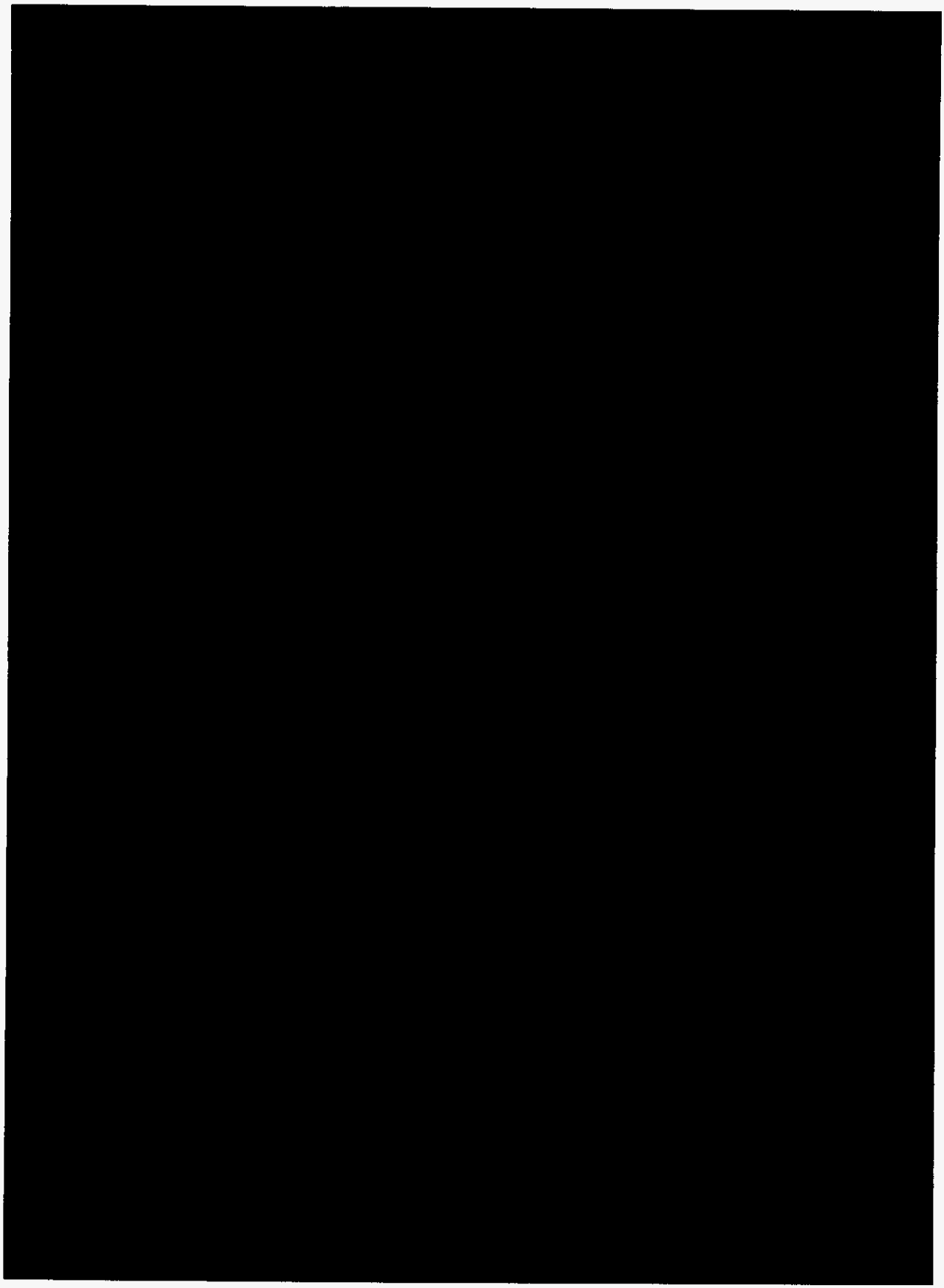
5.11.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall [redacted]

5.12 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.13 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.14 [redacted]





ARTICLE 6

PAYMENTS

6.1 Capacity Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 Energy Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 Start Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Fuel Transportation Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Fuel Transportation Payment. The calculation of the Monthly Fuel Transportation Payment is set forth in Section 9.2.2.

6.5 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission

tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., an Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] Days after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 600 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such

service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate and include any and all documentation of such Total Cost

provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 600 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted]

Buyer shall notify Seller of such election within 3 Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted] MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted] MW, Seller shall be entitled to either: [redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

[redacted]

ARTICLE 8

TOTAL FACILITY CAPACITY AND COMMENCEMENT OF SERVICE

8.1 Declaration of the Total Facility Capacity. Through notice to Buyer, Seller shall declare the Total Facility Capacity for each Contract Year pursuant to the procedures set forth in Section 8.2.

8.2 Declaration Prior to Each Contract Year.

8.2.1 Except as provided in Section 8.3.1.1 and 8.3.1.2, within 90 Days prior to the beginning of each Contract Year, Seller shall declare the Total Facility Capacity for such Contract Year. Such declaration shall be based on the demonstrated generating capability of the Facility as determined in accordance with Appendix E.

8.2.2 After Seller's declaration under Section 8.2.1, Buyer shall have the right to require a test to re-demonstrate the capability of the Facility as follows:

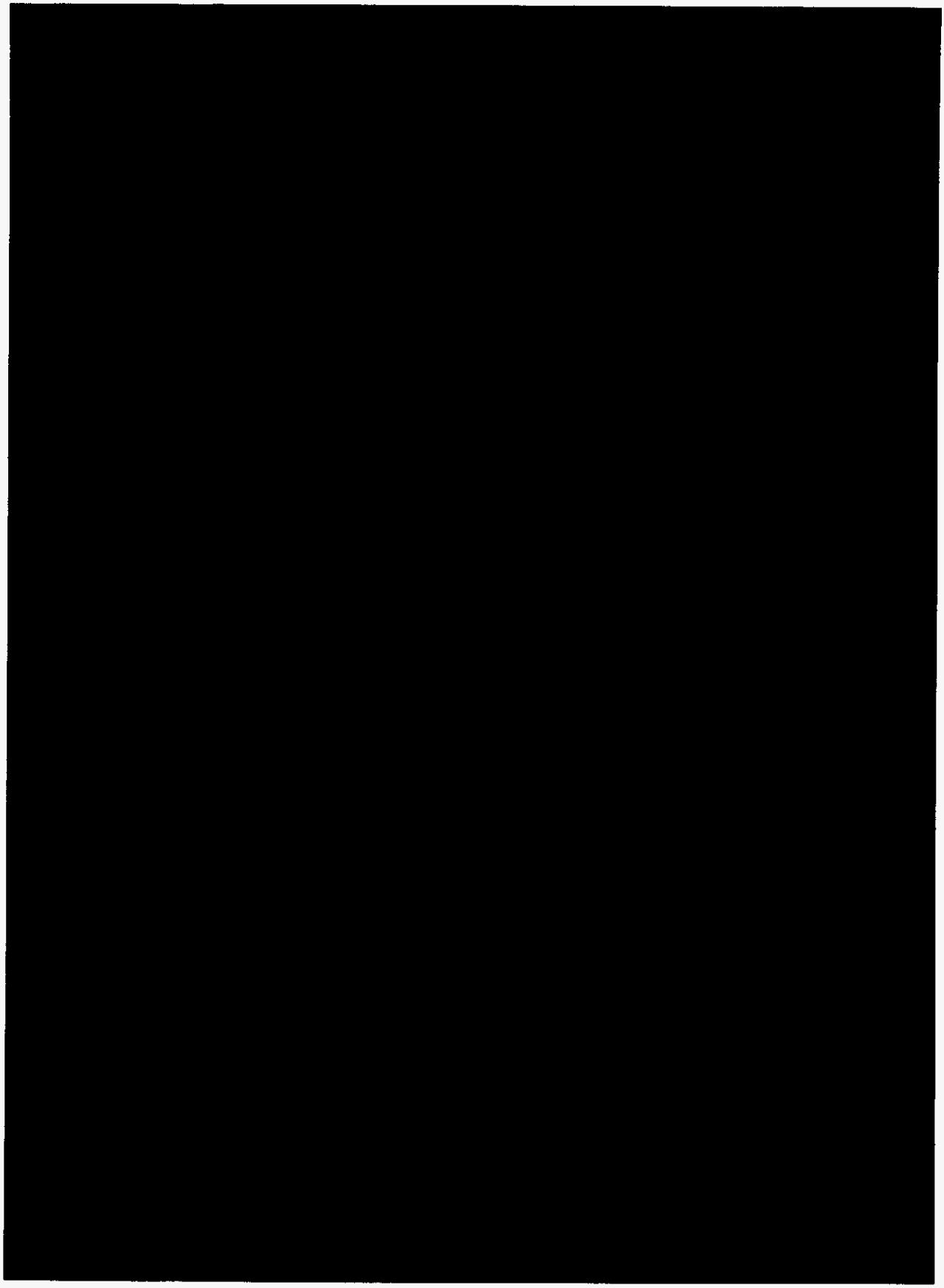
8.2.2.1 After Seller's declaration of the Total Facility Capacity for the first Contract Year, Buyer may by notice to Seller ("Test Notice") require Seller to conduct a test to re-demonstrate the capability of the Facility. Buyer shall provide any such Test Notice no later than 30 Days after the Service Commencement Date ("Initial Testing Deadline"). If Buyer timely provides the Test Notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

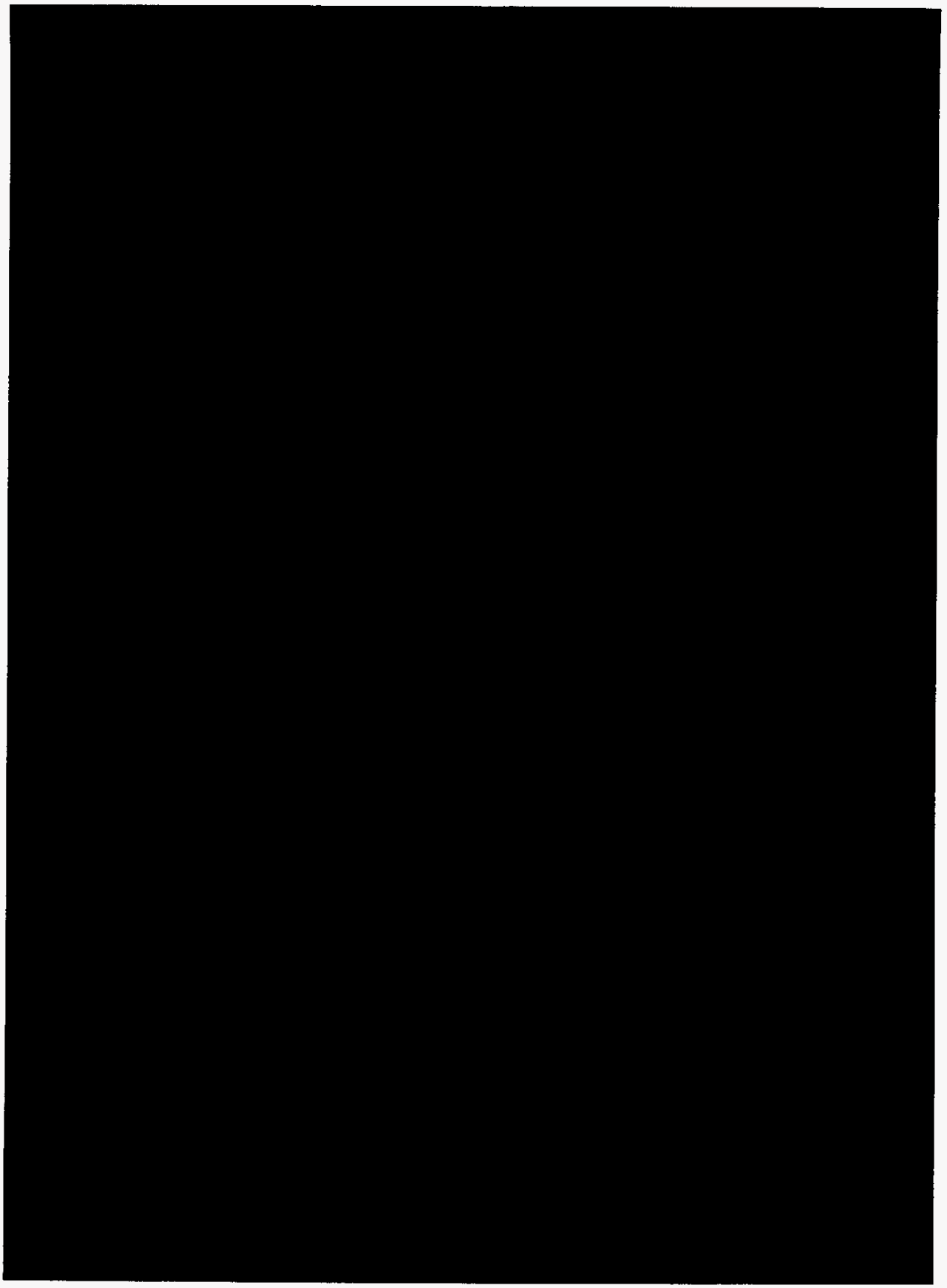
8.2.2.2 After the Initial Testing Deadline, if at any time Buyer has reasonable grounds for disputing Seller's declared amount of Total Facility Capacity (e.g., the delivery of energy by Seller in amounts less than Scheduled Energy), Buyer may provide to Seller a Test Notice to require Seller to conduct a test to re-demonstrate the capability of the Facility. Upon receipt of such notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

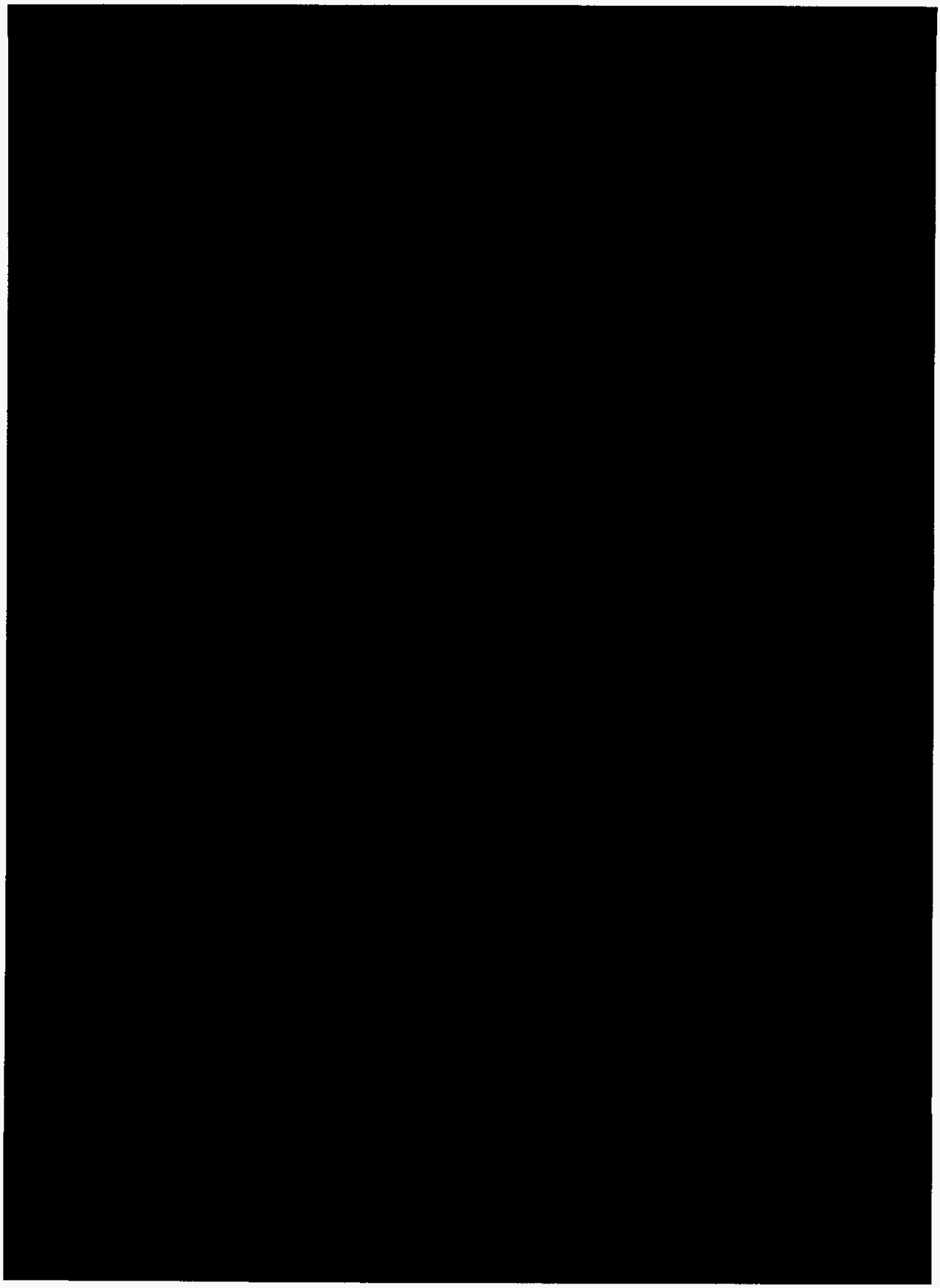
8.2.3 In the event that a test required by Buyer pursuant to Section 8.2.2 indicates that the generating capability of the Facility is different than the Total Facility Capacity declared pursuant to Section 8.2.1, Seller may (at its sole option) conduct additional test(s) of the Facility in accordance with Appendix E, such test(s) to be completed no later than 30 Days after the test conducted pursuant to Section 8.2.2. If Seller does not elect to conduct

such additional test(s), the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated by the test conducted pursuant to Section 8.2.2. If Seller does elect to conduct additional testing, Seller shall provide Buyer prior notice of the Day(s) of such test(s) and the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated through such additional test(s). If such test(s) is performed coincident with Buyer's Schedule for any Day(s), Buyer shall pay Seller the costs of testing (including Gas and operation and maintenance costs) that are the responsibility of Buyer through the application of the Monthly Energy Payment for all Delivered Energy provided to Buyer. To the extent such test(s) is performed during a time period in which energy will not be delivered to Buyer pursuant to a Schedule, Seller shall be responsible for all costs of testing (including Gas and operation and maintenance costs) and shall be entitled to utilize all energy produced during testing for its own purposes.

8.2.4 If the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3 as a result of a Test Notice provided by Buyer on or before the Initial Testing Deadline, the Total Facility Capacity shall be adjusted retroactively to the Service Commencement Date. In all other cases when the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3, the Total Facility Capacity shall be adjusted retroactively to the date of the applicable Test Notice. All capacity billing under Section 6.1 shall (if necessary and as soon as practicable) be retroactively adjusted as appropriate (with interest at the Interest Rate) to reflect such adjustment of the Total Facility Capacity.







[redacted]

ARTICLE 9

FUEL ARRANGEMENTS

9.1 Seller's Commitment. Subject to the provisions of this Agreement, Seller will use Commercially Reasonable Efforts to provide to the Facility the volume of Gas needed to provide Scheduled Energy.

9.2 Gas Transportation Arrangement and Charges.

9.2.1 Subject to the provisions of this Agreement, Seller will utilize up to [redacted] MMBtu per day of firm transportation capacity on the pipeline system of SNG from SNG's Zone 0 to Zone 2 under SNG's Contract Number FSNG284 constructed under South System I, Phase II expansion that was placed in service on June 1, 2003 for deliveries to Point Code 808000, Plant Harris, as amended ("SNG Contract") as necessary to provide Scheduled Energy under this Agreement. To the extent energy is supplied to Buyer from the Facility, Seller shall afford Buyer's Schedule priority with regard to the use of such transportation capacity that is available; provided, however, if a portion of the total amount of transportation capacity procured by Seller to the Plant is unavailable for any hour(s), Seller shall be permitted to reduce on a pro rata basis the amount of transportation capacity that it will utilize in order to satisfy Buyer's Schedule.

9.2.2 Buyer shall pay to Seller a Monthly Fuel Transportation Payment which shall be an amount equal to the product resulting from multiplying [redacted] MMBtu by the sum of: [redacted]

9.2.3 [redacted]

9.2.4 Buyer acknowledges that Seller may have the right pursuant to Exhibit E of the SNG Contract to terminate that contract; however, Seller shall exercise that right with respect to the transportation capacity necessary to provide Scheduled Energy under this Agreement only if Buyer and Seller agree on mutually acceptable replacement transportation arrangements.

9.2.5 Buyer acknowledges that SNG may impose imbalance, cash-out and other types of charges, including penalty charges, pursuant to its FERC approved tariff under certain conditions ("Penalty Charges"). Buyer agrees to be responsible for and pay or reimburse Seller for any Penalty Charges billed to Seller by SNG that result from any action or failure to act of Buyer under this Agreement. The Parties agree to cooperate in order to attempt to minimize Penalty Charges.

9.2.6 In the event that accommodating Buyer's Schedule would require Gas transportation capacity in addition to that set forth in Section 9.2.1, Seller shall make Commercially Reasonable Efforts to obtain (if available) additional capacity at Buyer's expense and Buyer shall reimburse Seller based on SNG's interruptible transportation rate from Zone 0 to Zone 2 in effect at the time. To the extent Seller is unable to obtain such additional capacity at or below such interruptible transportation rate and such capacity is available, Seller shall make Commercially Reasonable Efforts to provide Buyer the option of having Seller purchase such additional capacity at the higher rate. If Buyer desires to have Seller purchase such additional capacity at the higher rate, Seller shall make Commercially Reasonable Efforts to obtain such capacity to accommodate Buyer's Schedule and Buyer shall reimburse Seller for all associated costs. To the extent that Buyer does not desire to have Seller purchase such additional capacity at the higher rate or Seller is unable to obtain such capacity, Seller shall have a Delivery Excuse to that extent.

9.3 Interruption of Gas Supplies

9.3.1 In the event that Gas supplies are interrupted due to any circumstance affecting Seller's Gas suppliers that qualifies as an event of force majeure as defined in the North American Energy Standards Board's Base Contract for Sale and Purchase of Natural Gas:

A. Seller shall use Commercially Reasonable Efforts to arrange for alternate Gas supplies to overcome such an interruption. If alternate Gas supplies are available, Seller shall offer to Buyer, and Buyer shall have the option to immediately accept, such alternate Gas supplies at the price quoted by Seller.

B. If Seller is unable to arrange for alternate Gas supplies or if Buyer does not accept such alternate Gas supplies pursuant to subparagraph A above, Buyer may

arrange to sell alternate gas supplies to Seller at the Gas Price (as defined in Appendix B) by delivering such Gas to SNG at a point on its pipeline at which Seller can schedule receipts of such Gas under the SNG Contract. Buyer shall cooperate with Seller and SNG in order to ensure that such supplies are nominated, scheduled and delivered to SNG for transportation under the SNG Contract and under the terms of SNG's FERC approved tariff. Buyer shall be responsible for any Penalty Charges resulting from any difference between the volume scheduled for delivery by Buyer to and receipt by SNG and the actual volume delivered by Buyer to and received by SNG.

9.3.2 In the event that there is no arrangement for alternate Gas supplies under Section 9.3.1, the interruption of Gas supplies described in Section 9.3.1 shall constitute a Delivery Excuse as defined in this Agreement.

9.3.3 Notwithstanding any other provision of this Agreement, Seller shall not be obligated to obtain or use any Gas storage services in order to provide Gas under this Agreement.

9.4 Scheduling Changes. In the event that Buyer requests a Schedule change pursuant to Section 5.1.2 after the Scheduling Deadline, Seller shall quote a price for supplying incremental Gas needed to accommodate an increase in Scheduled Energy (subject to Gas availability and the ability to schedule delivery of Gas) or for selling excess Gas resulting from a decrease in Scheduled Energy, as appropriate. Upon receipt of Seller's quote, Buyer shall immediately exercise one of the following options: (i) not changing the existing Schedule: (ii) proceeding with the requested Scheduling Change and the increase or decrease in Gas supplies based on the quoted price (to buy the incremental Gas supply, or to sell the excess Gas supply, as applicable), or (iii) proceeding with the increase (if applicable) in Scheduled Energy and

notifying Seller that Buyer will supply the required incremental Gas supply utilizing the procedures set forth in Section 9.3.1B.

ARTICLE 10

ELECTRIC METERING

10.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

10.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

10.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

10.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount

of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 11

BILLING AND PAYMENT

11.1 Timing and Method of Payment. Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable on [redacted] ("Payment Due Date"). If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

11.2 Late Payment. Amounts that are owed Seller shall, if not remitted within the time period specified under Section 11.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 21.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

11.3 Disputed Billings. In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. Notwithstanding such dispute, [redacted]

[redacted]

11.4 Adjustments. If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is

resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than [redacted] Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] Days after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline,

Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter

event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable

Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within 30 Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 18.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

13.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than 30 Days thereafter, Seller may initiate a Change in Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent

with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

13.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 14

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

14.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) except for any Taxes included in the Gas Charges, Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission,

and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

14.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

14.3 Limitation of Liability.

14.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

14.3.2 SUBJECT TO SECTION 16.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

14.3.3 In the event that any provision of this Section 14.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 14.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 14.2 or limit the remedies set forth in this Agreement for an Event of Default.

14.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 15

FORCE MAJEURE EVENT

15.1 Force Majeure Event Defined.

15.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

15.1.2 Notwithstanding anything contained in Section 15.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

15.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

15.2.1 The non-performing Party shall give the other Party written notice within 3 Business Days of the commencement of the Force Majeure Event, with available details to be supplied within 15 Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

15.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

15.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

15.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

15.3 Effect of Force Majeure Event.

15.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

15.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

[redacted]

[redacted]

ARTICLE 16

EVENT OF DEFAULT

16.1 **Event of Default.** The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

16.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within 15 Days after receiving written notice of such failure from the Party to which such payments are due;

16.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

16.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its

debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

16.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within 60 days of the filing thereof;

16.1.5 The failure of any Party to comply with the requirements of Article 20 regarding creditworthiness and/or security;

16.1.6 The failure of a Party to comply with the requirements of Article 19 regarding assignment;

16.1.7 Any representation or warranty made by a Party under Article 17 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within 30 Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

16.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

[redacted]

16.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for 30 Days after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of 30 Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed 90 Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 16.1.10 shall not apply to: (i) any event described in Sections 16.1.1 through 16.1.9; (ii) any event described in Sections 5.10, 5.11 and 8.3 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 16.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party".

16.2 Exclusive Remedies.

16.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

16.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than 20 Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 21.3 and 21.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in Sections 16.2.3 or 16.2.4 below. The exercise by a Party of its rights under this Section 16.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

16.2.3 With respect to an Event of Default by or attributable to Buyer, within 15 Days after Seller's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within 30 Days after such notice, the two independent

parties shall select a third independent party to determine the Seller's Damages. Within 60 Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within 5 Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 18 and the arbitration order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration finding or order. As used herein, "Seller's Damages" [redacted]

16.2.4 With respect to an Event of Default by or attributable to Seller, within 15 Days after Buyer's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within 30 Days after such notice, the two

independent parties shall select a third independent party to determine the Buyer's Damages. Within 60 Days after such notice, the 3 independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within 5 Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arithmetic procedures of Article 18 and the arithmetic order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration finding or order. As used herein, "Buyer's Damages" means [redacted]

ARTICLE 17

REPRESENTATIONS AND WARRANTIES

17.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

17.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

17.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

17.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a breach or default under any evidence of its indebtedness or any other agreement or instrument to

which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

17.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

17.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 18

DISPUTE RESOLUTION

18.1 Senior Officers.

18.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and, unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

18.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

18.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

18.2 Arbitration.

18.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 18.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will be made by notice to the other Party and to the AAA within 10 Days or, in the case of payment disputes, 5 Days after the date of the giving of notice of the demand for arbitration. The

arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within 10 Days or, in the case of payment disputes, 5 Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

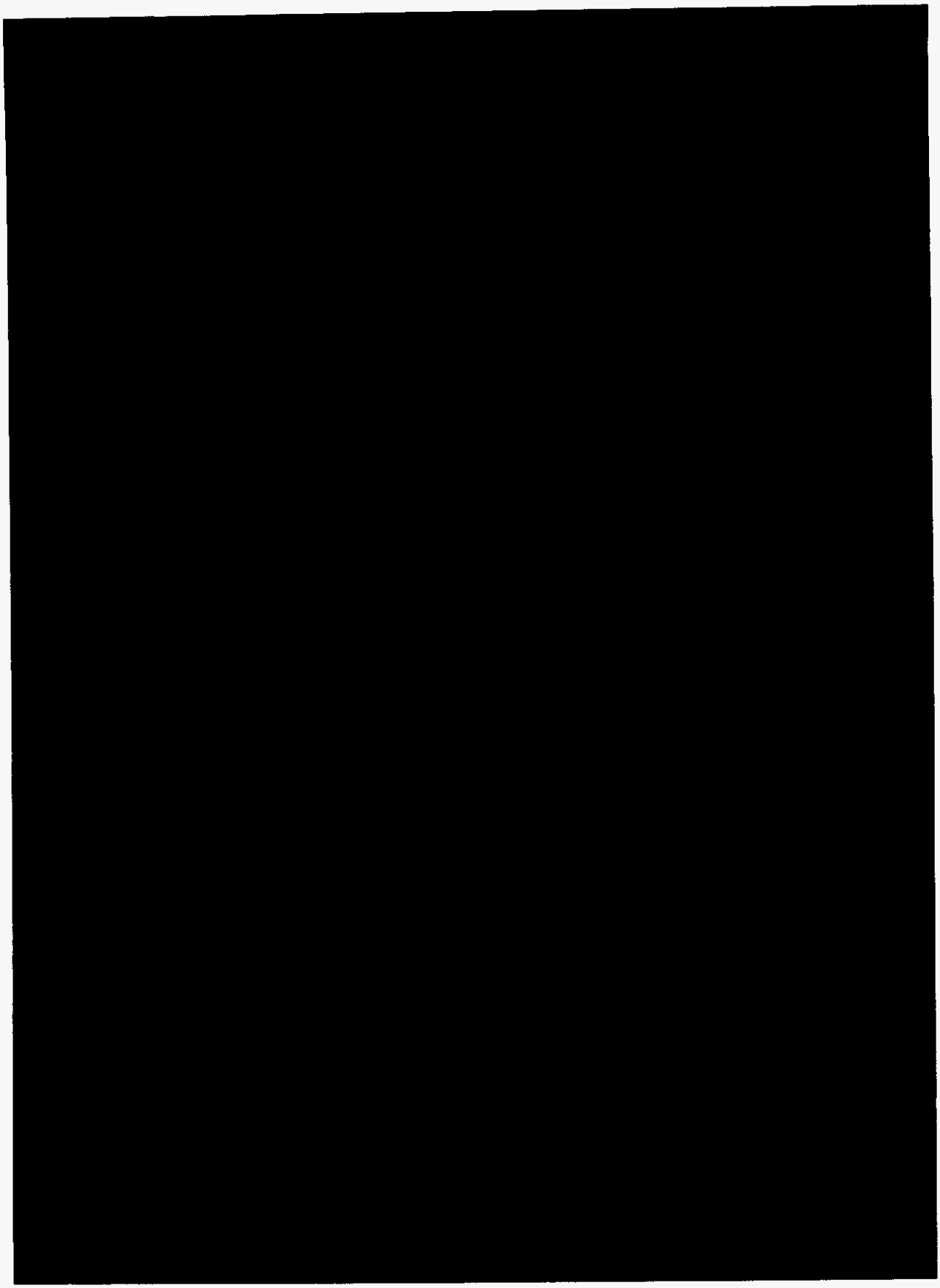
18.2.2 Subject to Section 16.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 21.2; provided further, notwithstanding any provision in Article 21, Confidential Information, to the extent relevant, may be disclosed by any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

18.3 Binding Nature of Proceedings. Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 18.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 19

ASSIGNMENT

19.1 Assignment. Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with [redacted]



[redacted]

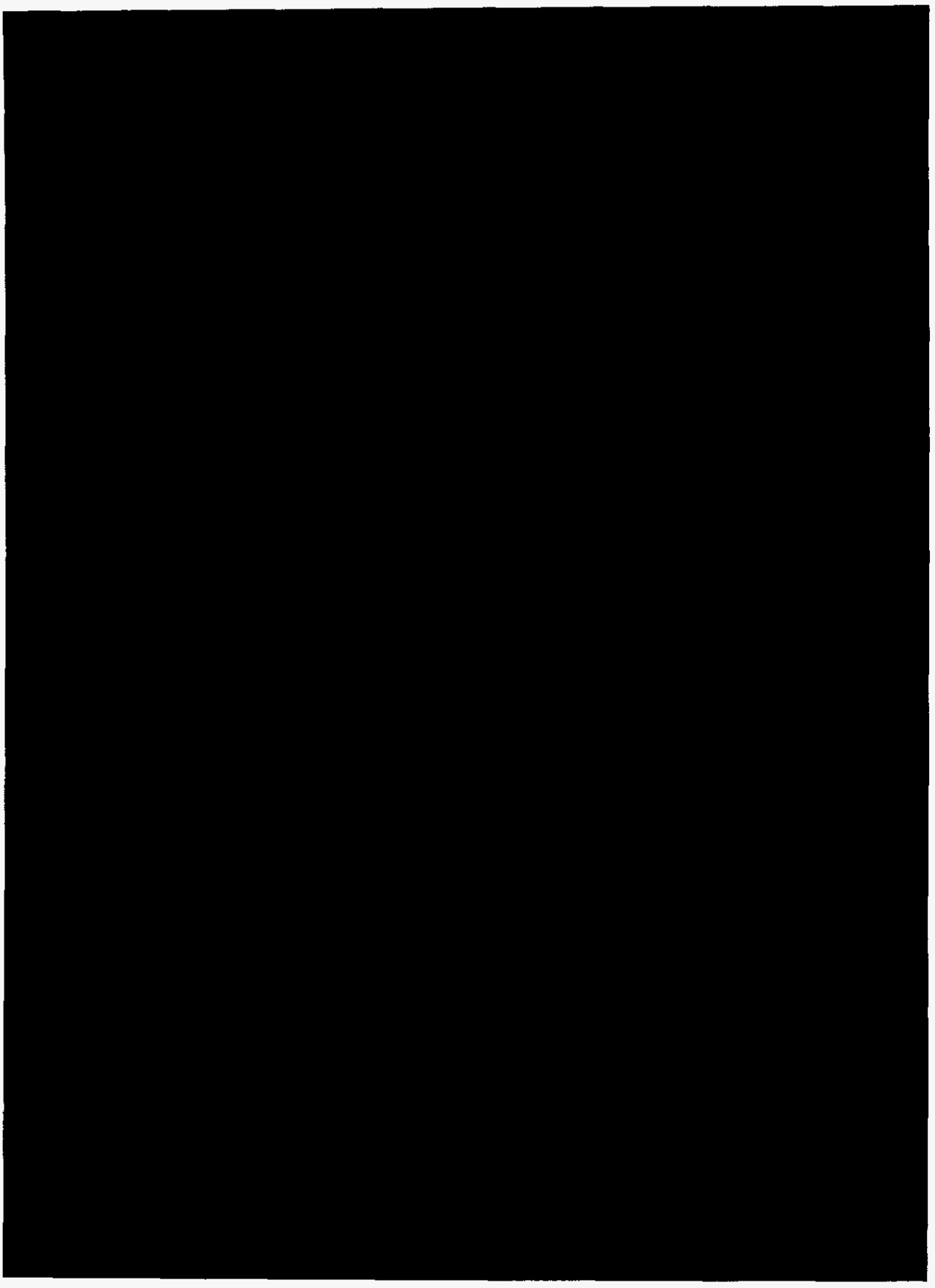
who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

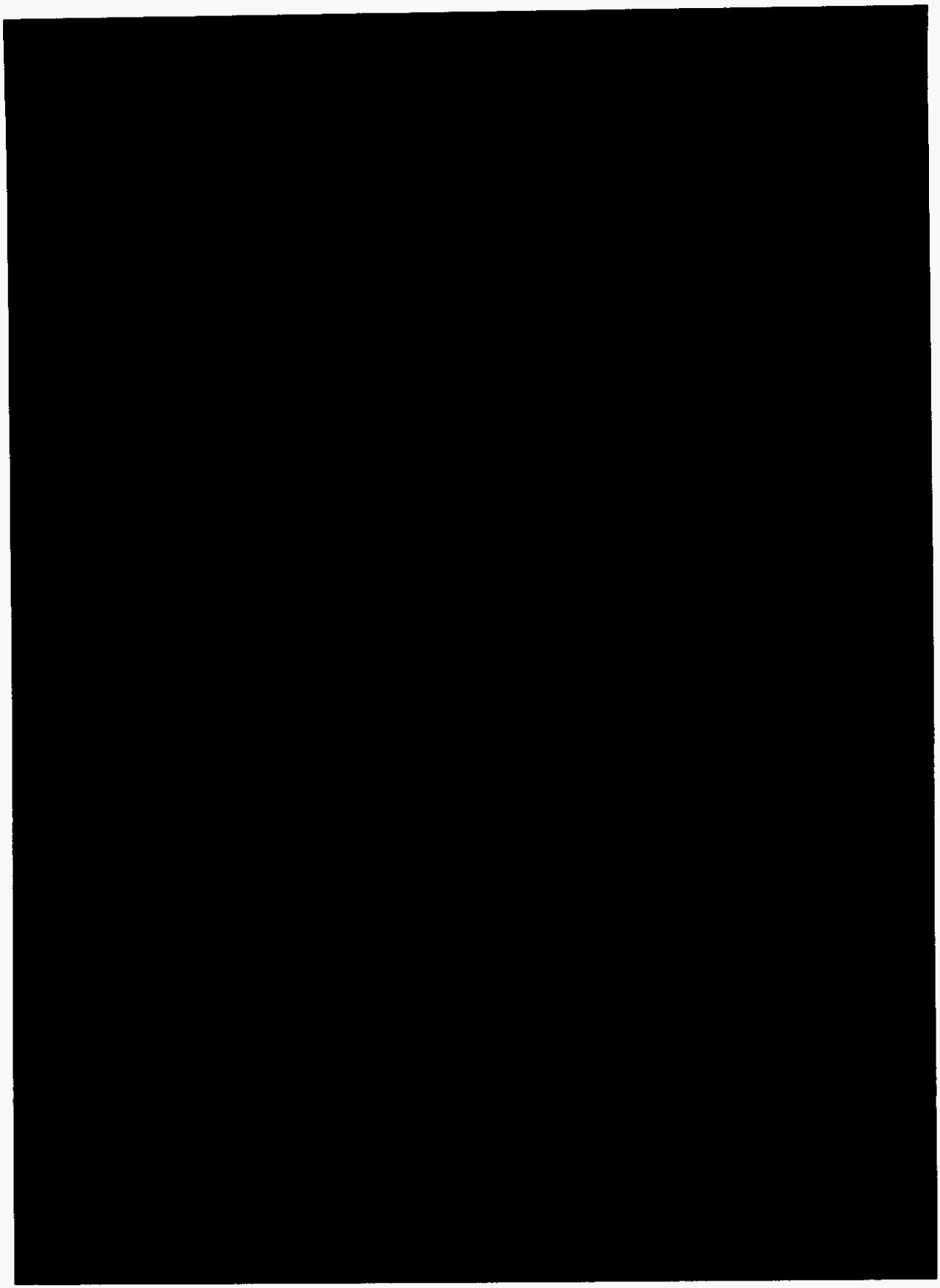
19.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions"). Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

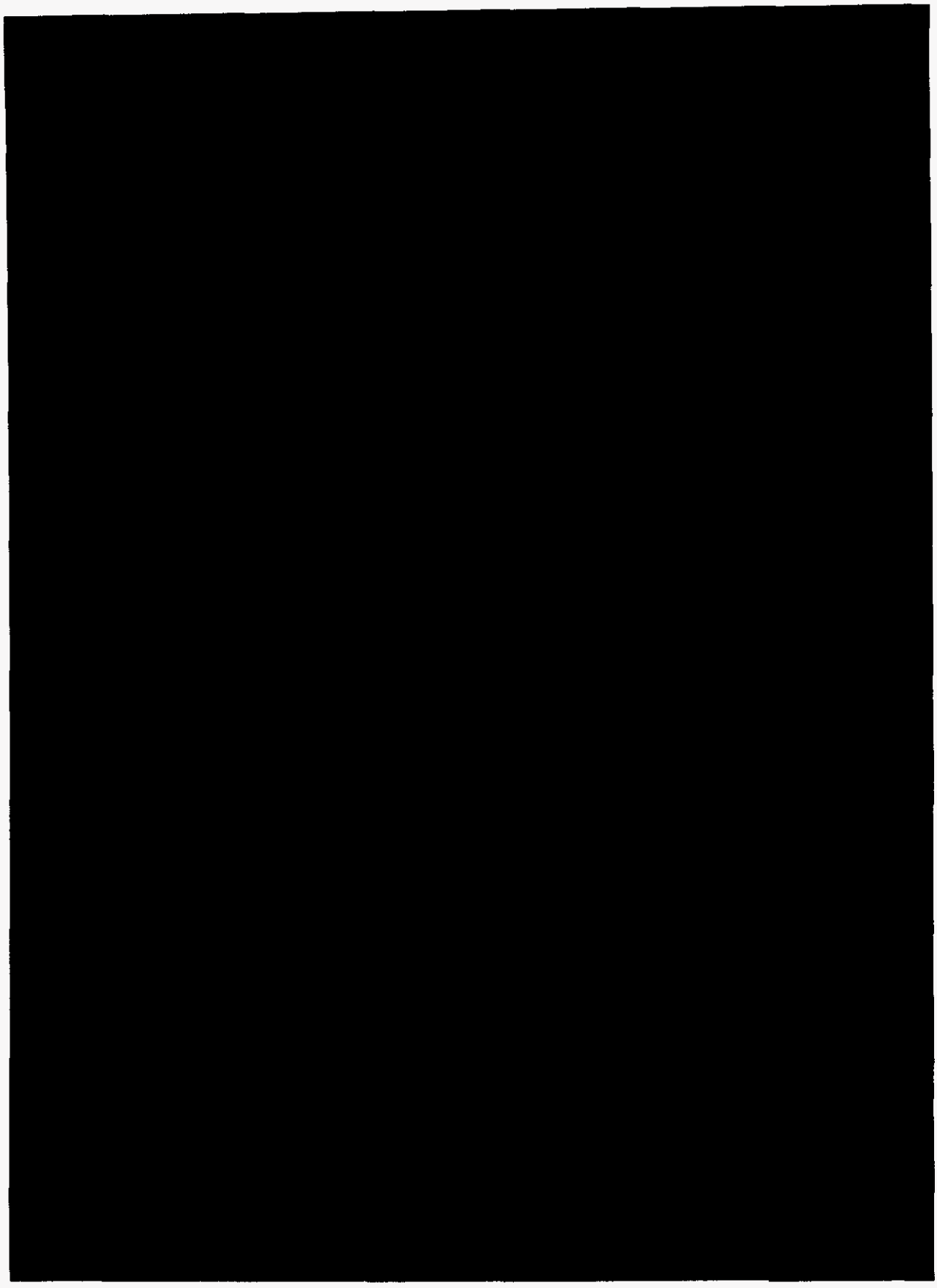
ARTICLE 20

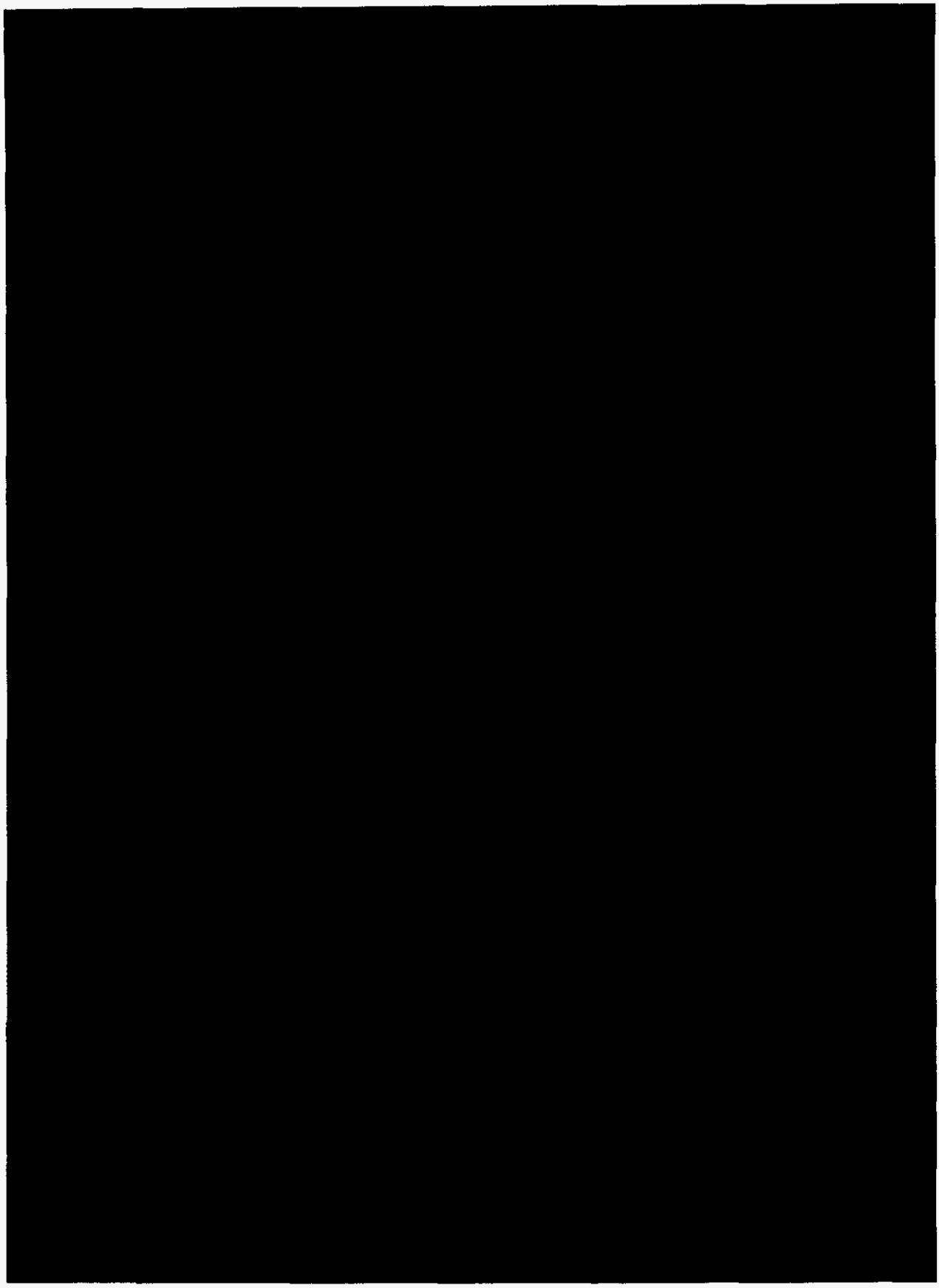
CREDITWORTHINESS AND SECURITY

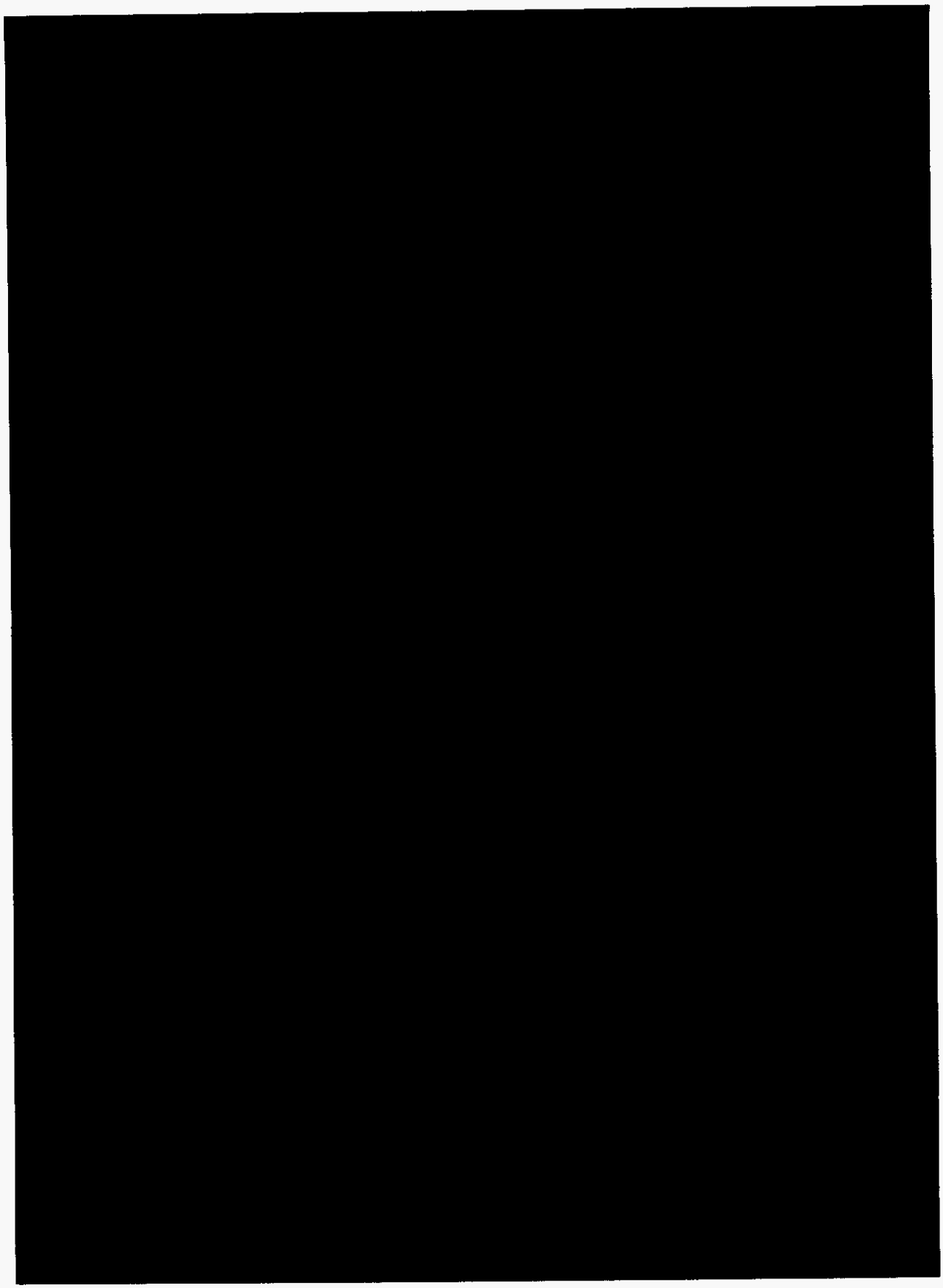
20.1 [redacted]

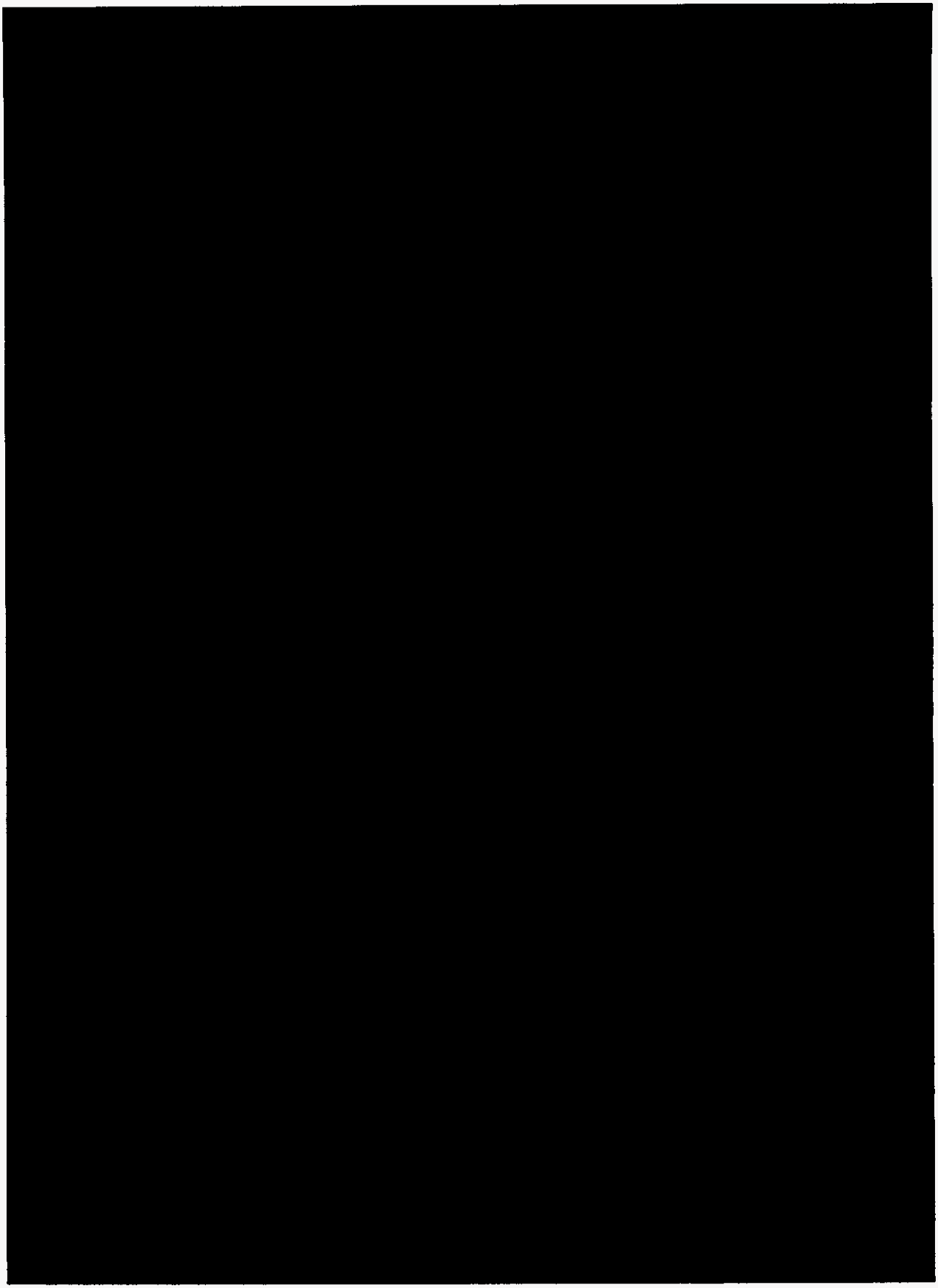


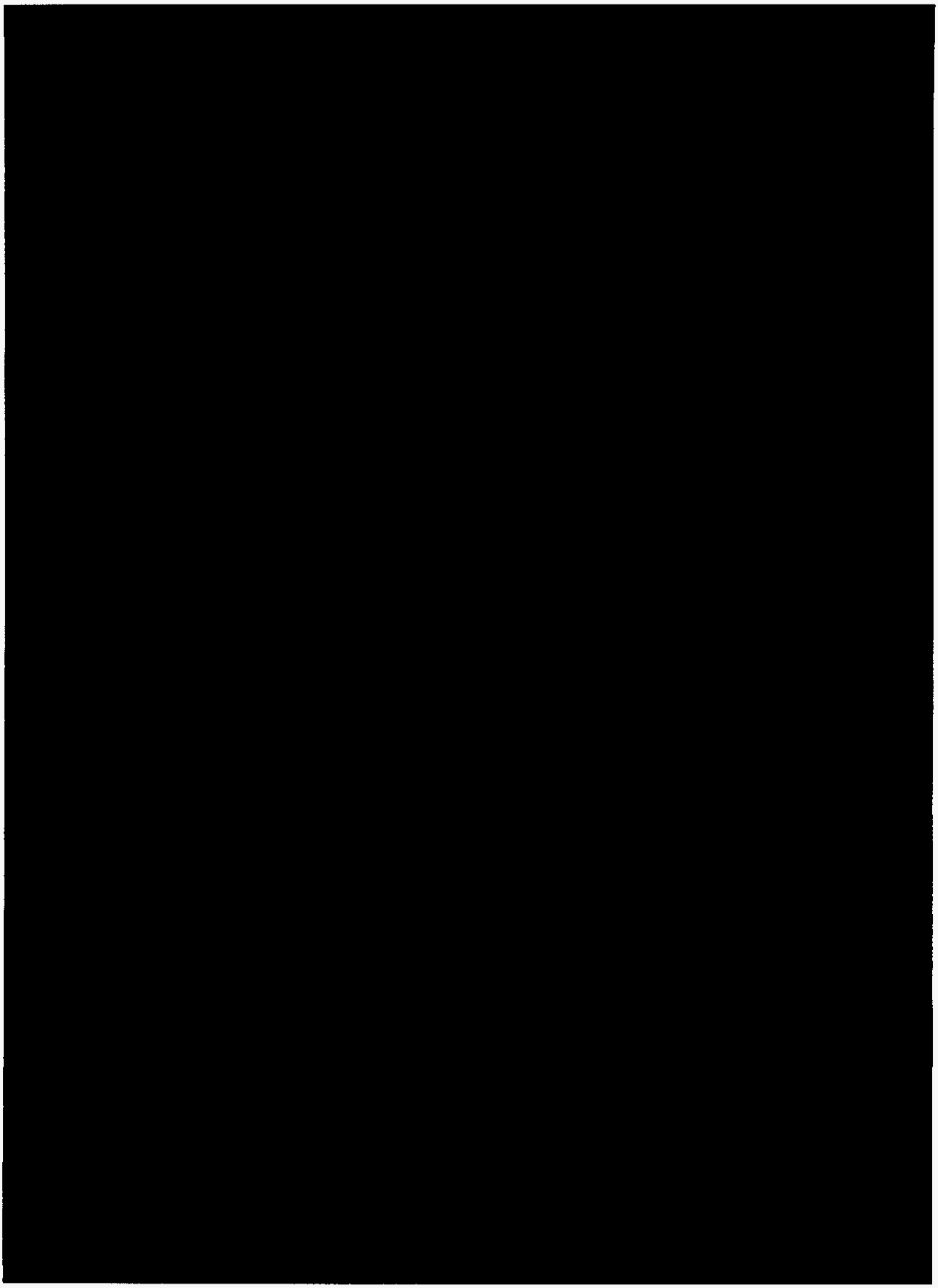












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ARTICLE 21

MISCELLANEOUS

21.1 Governing Law; Waiver of Jury Trial.

THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE,

REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

21.2 Confidentiality.

21.2.1 Scope of Protection.

(i) For purposes of this Section 21.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other

Persons in connection with the acquisition of all or a significant portion of the assets or stock of Southern Power or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Southern Power or any of its Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SEARUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to maintain such confidentiality; and (iii) Seller has notified Buyer of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the

otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or

other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally

compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 21.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 21.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 21.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential

Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any

Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

[redacted]

21.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 14.2 and 14.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

21.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

21.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

21.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated

period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

21.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

21.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

21.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

21.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

21.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer

of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

21.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

21.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

21.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President, General Counsel and Assistant Secretary
Southern Power Company
600 North 18th Street
Birmingham, Alabama 35203

Telephone: 205-257-0472
Facsimile: 205-257-2027

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305-552-2905

Either Party may change the information set forth in this Section 21.14 by giving written notice to the other Party in the manner prescribed by this Section.

21.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

21.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

21.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the

transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

21.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

21.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer 60 Days written notice in which event Southern Company

Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

21.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

21.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix H. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Southern Power Company

BY: _____

NAME: William N. McKenzie

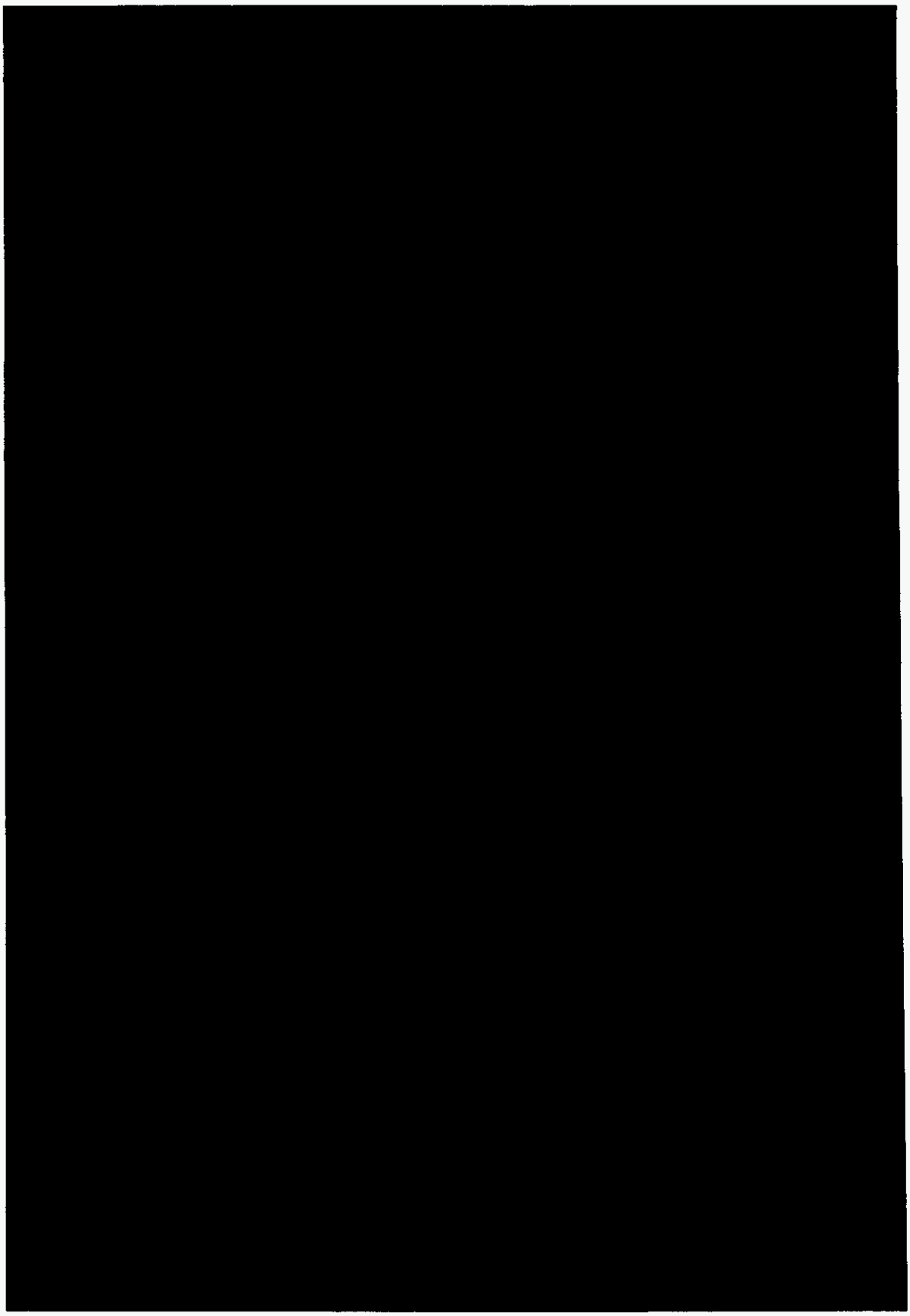
TITLE: Vice President

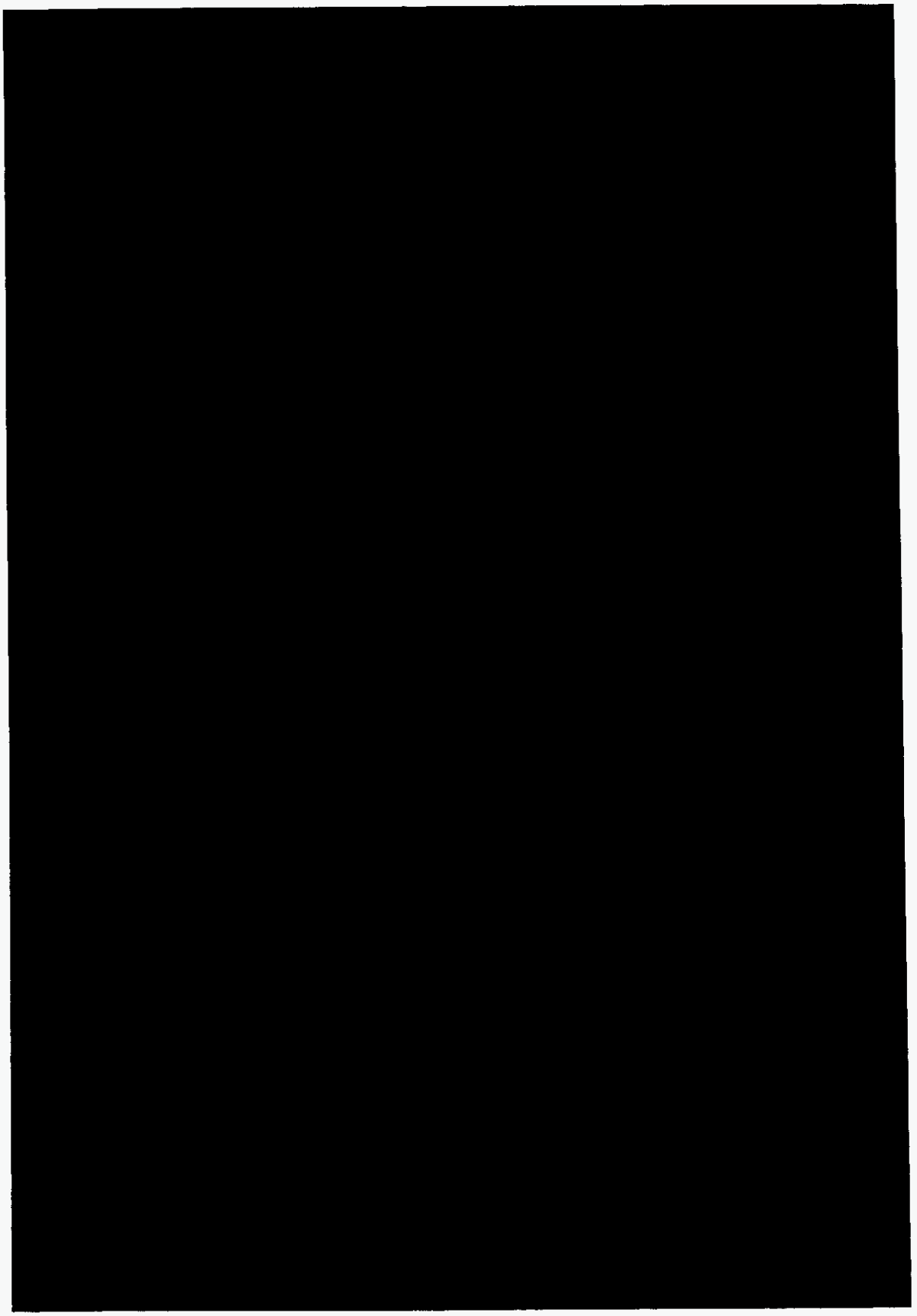
FLORIDA POWER & LIGHT COMPANY

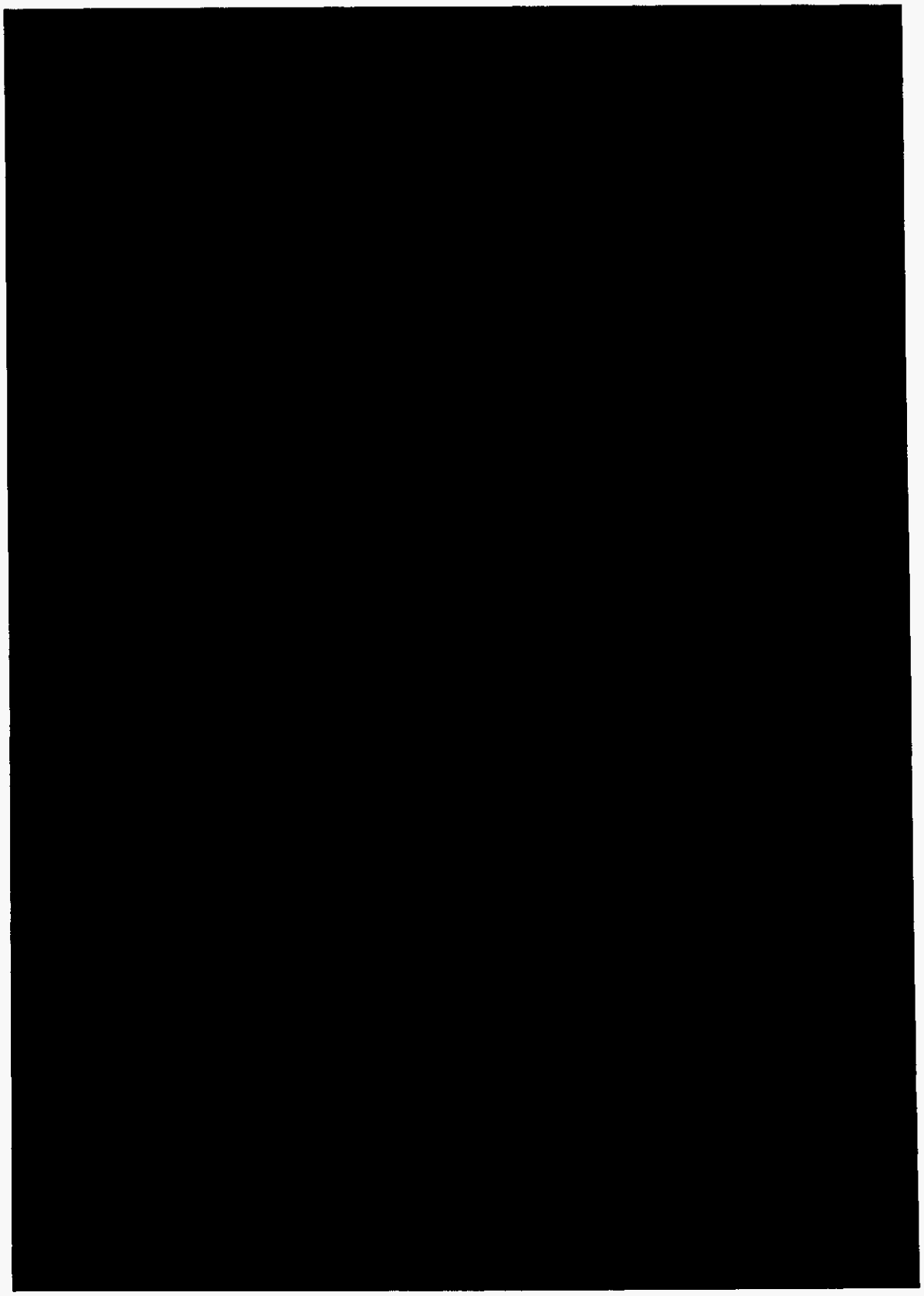
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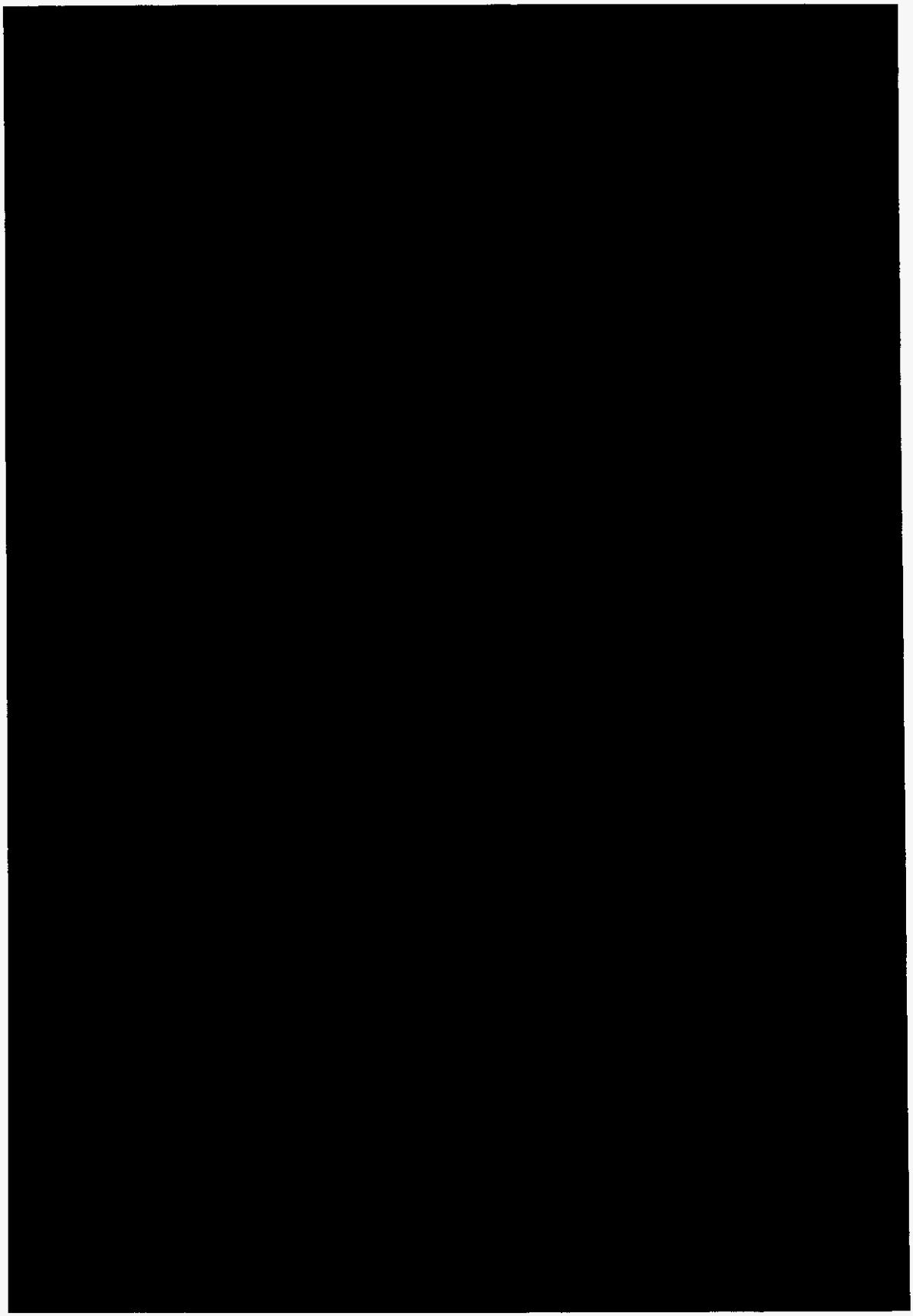
NAME: Terry L. Morrison

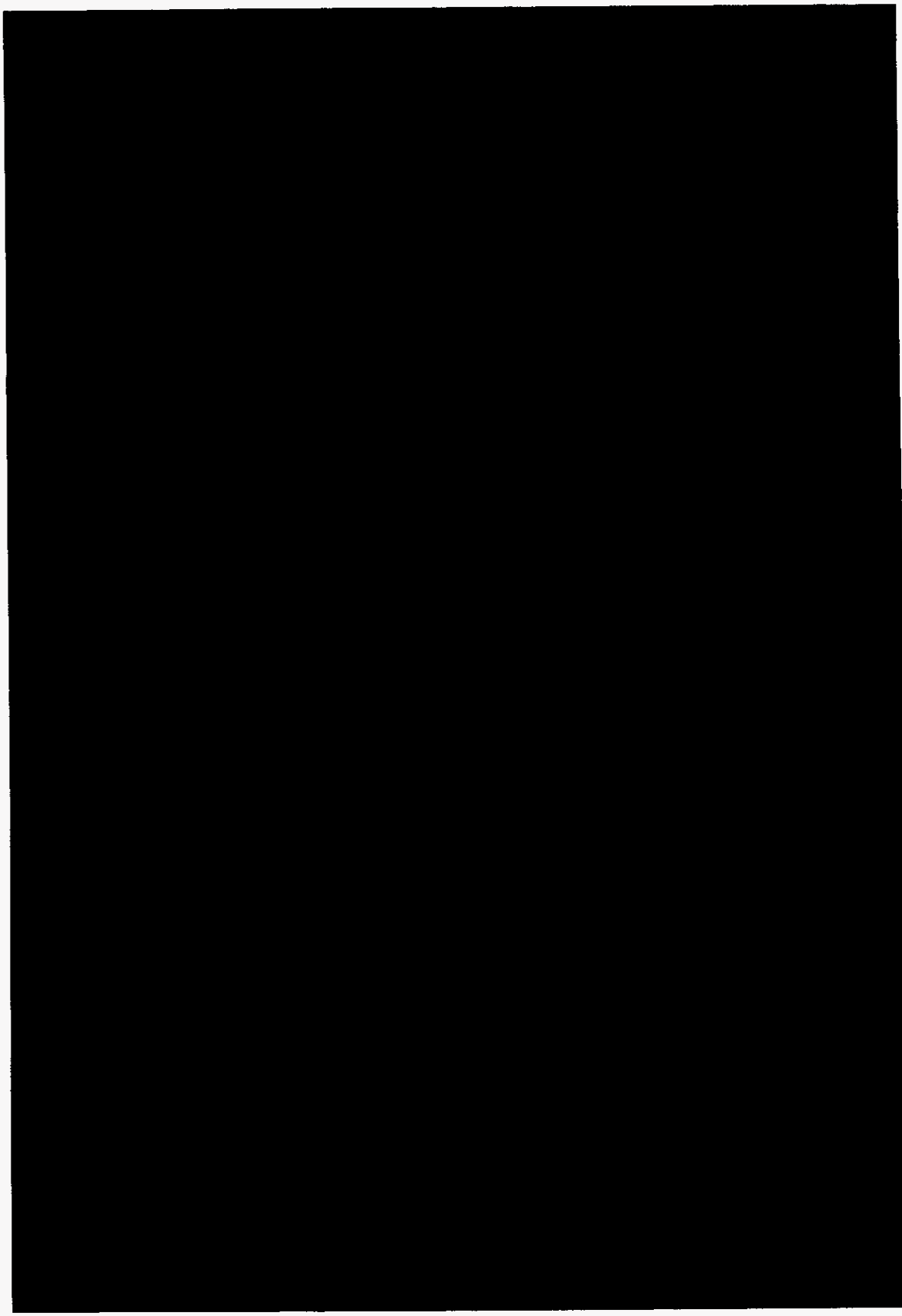
TITLE: Vice President

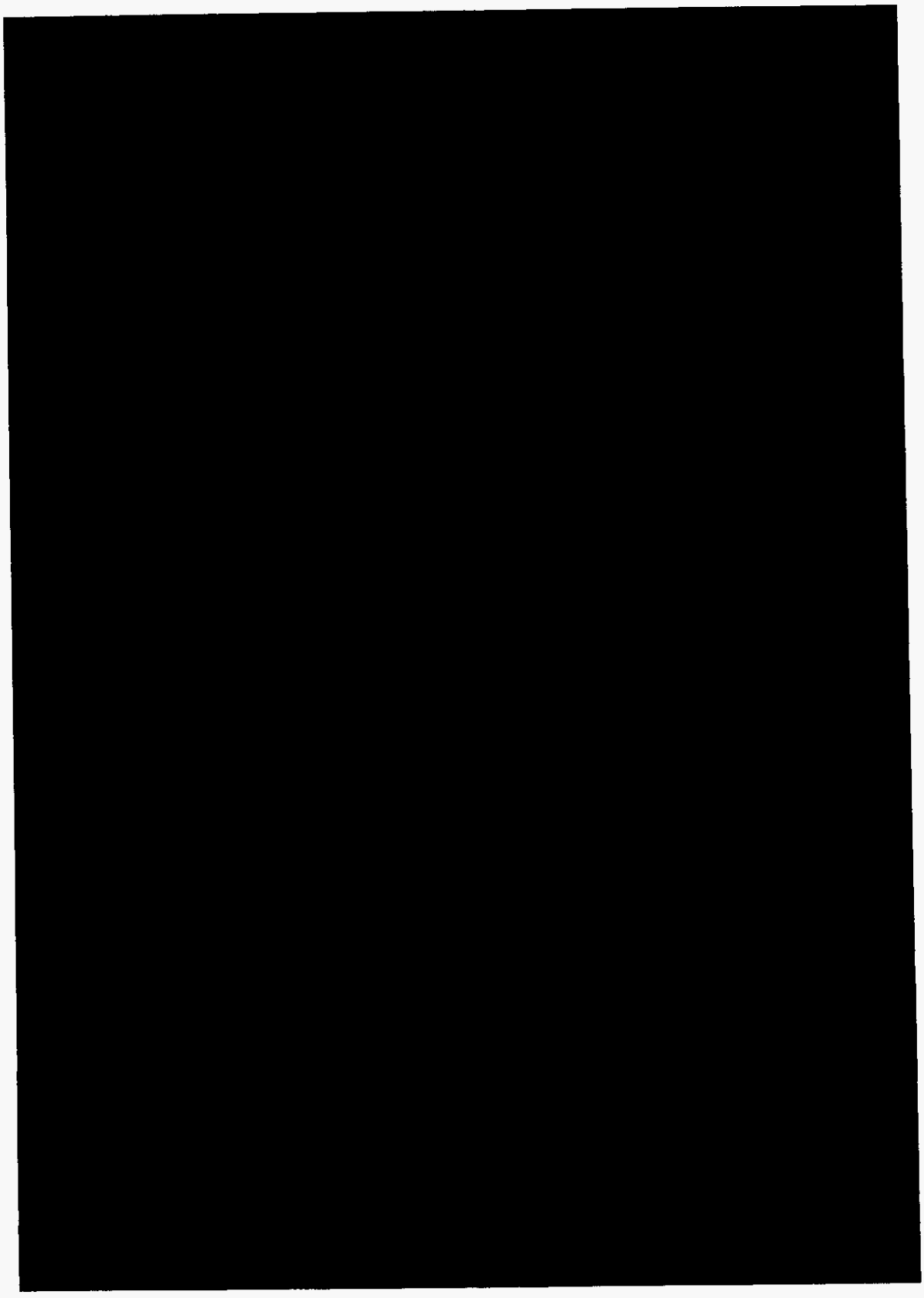


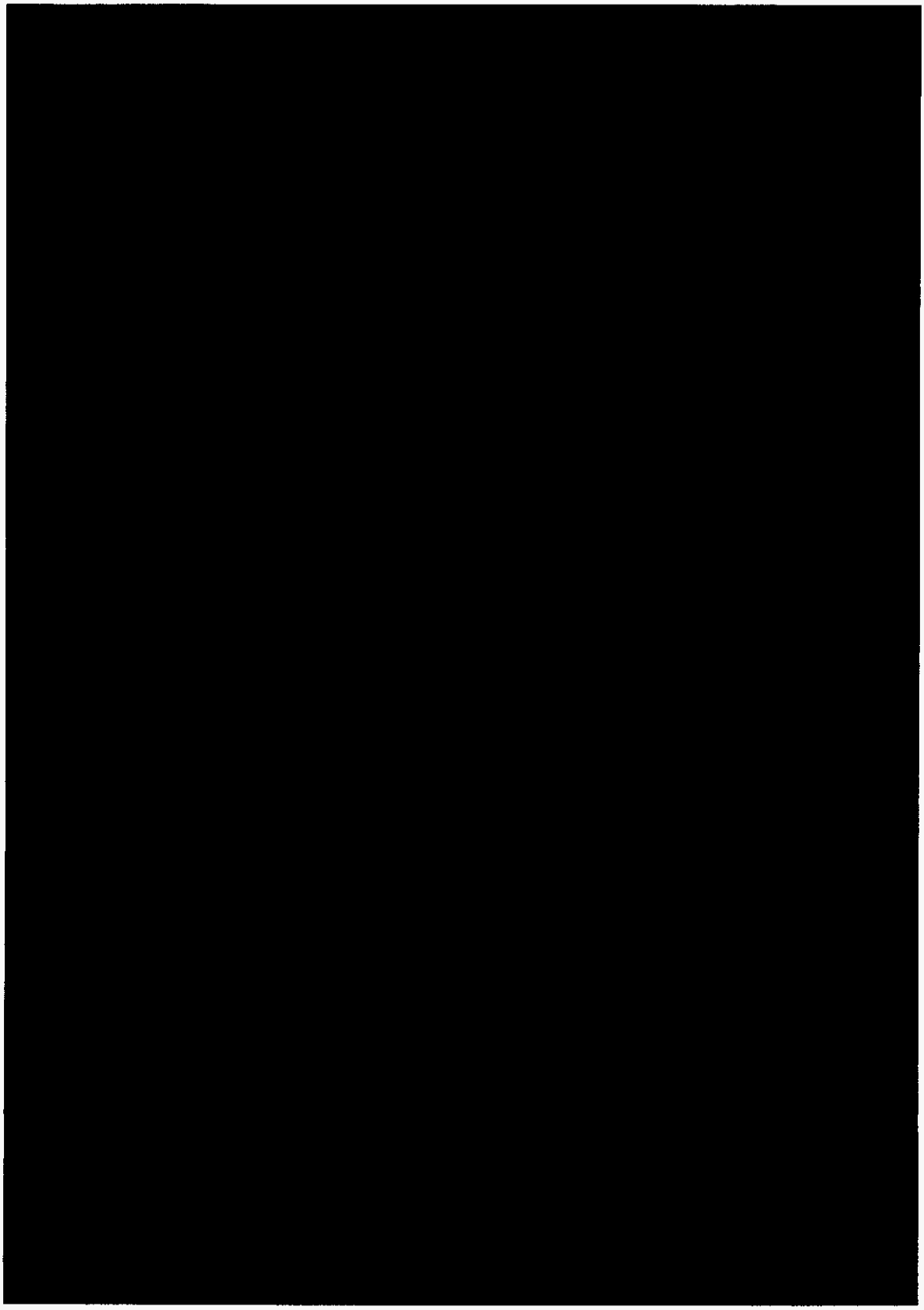


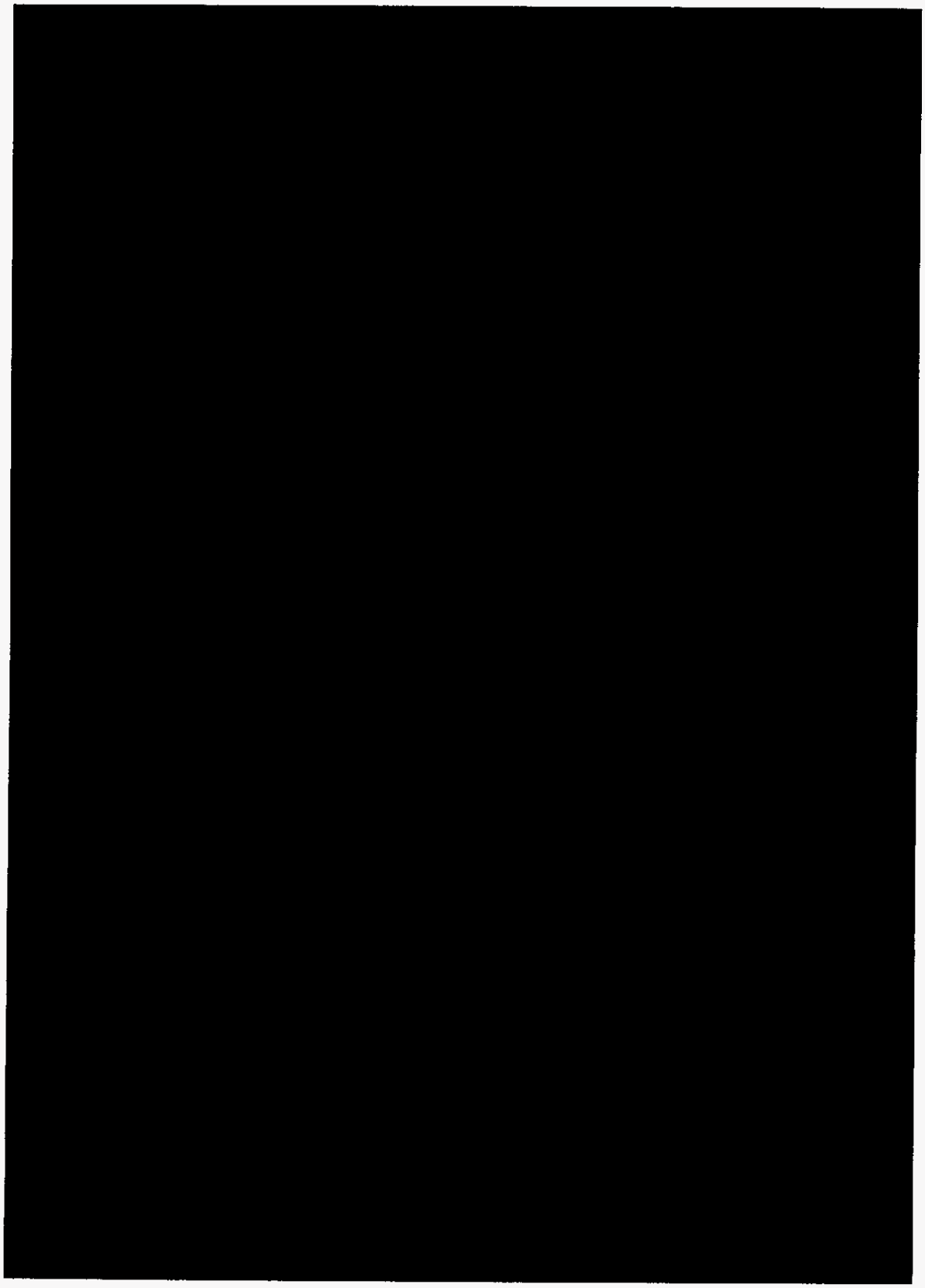


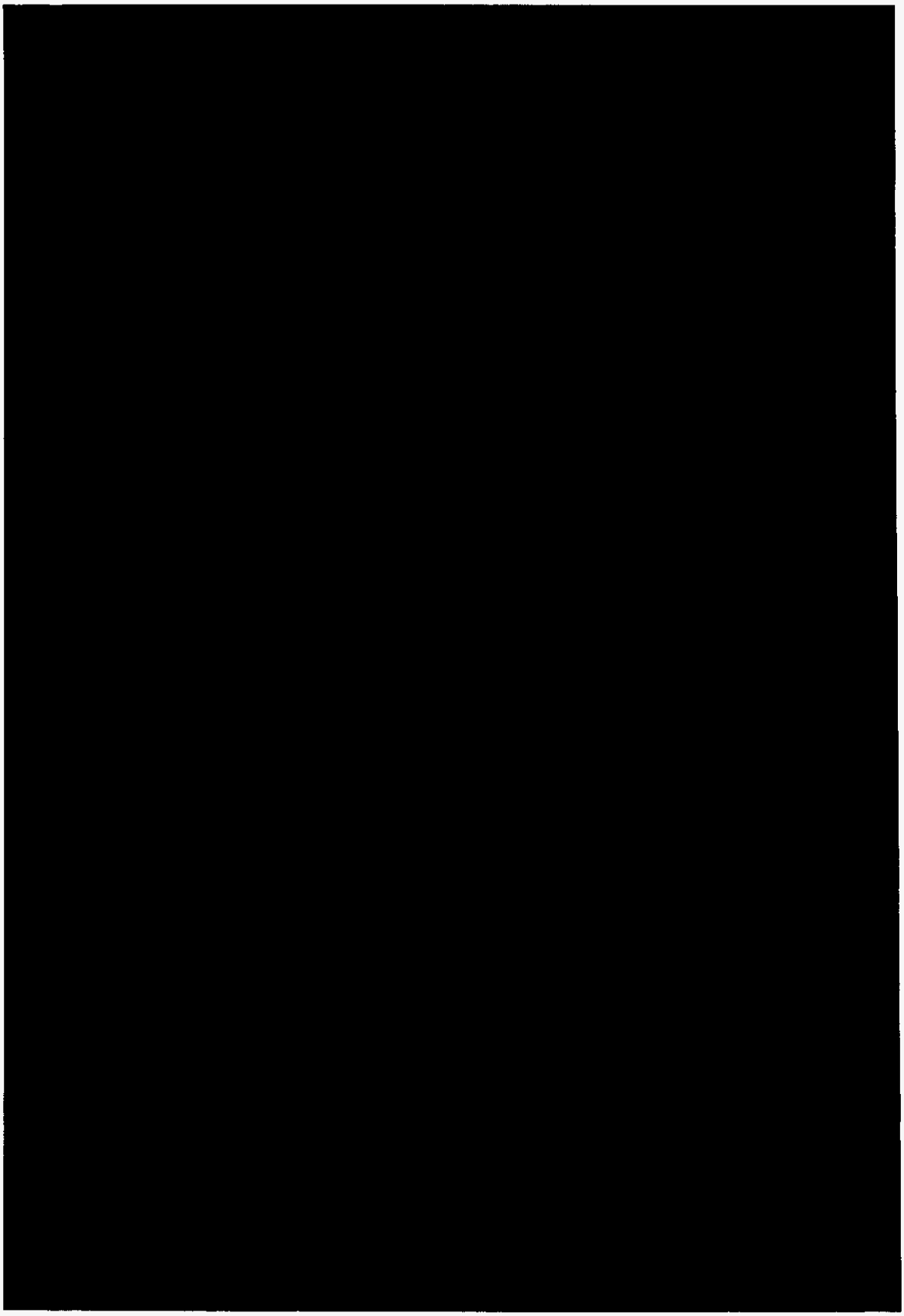


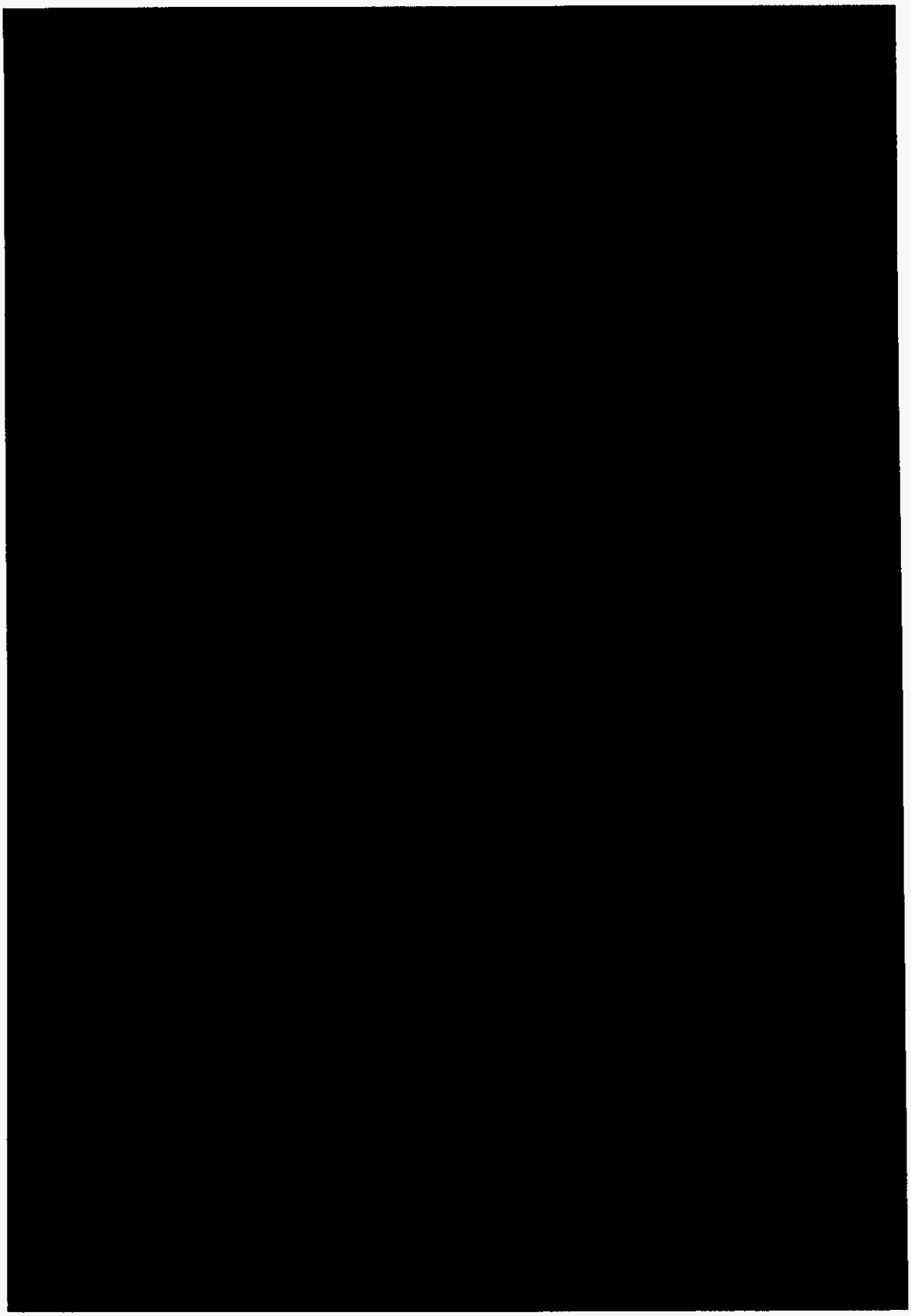


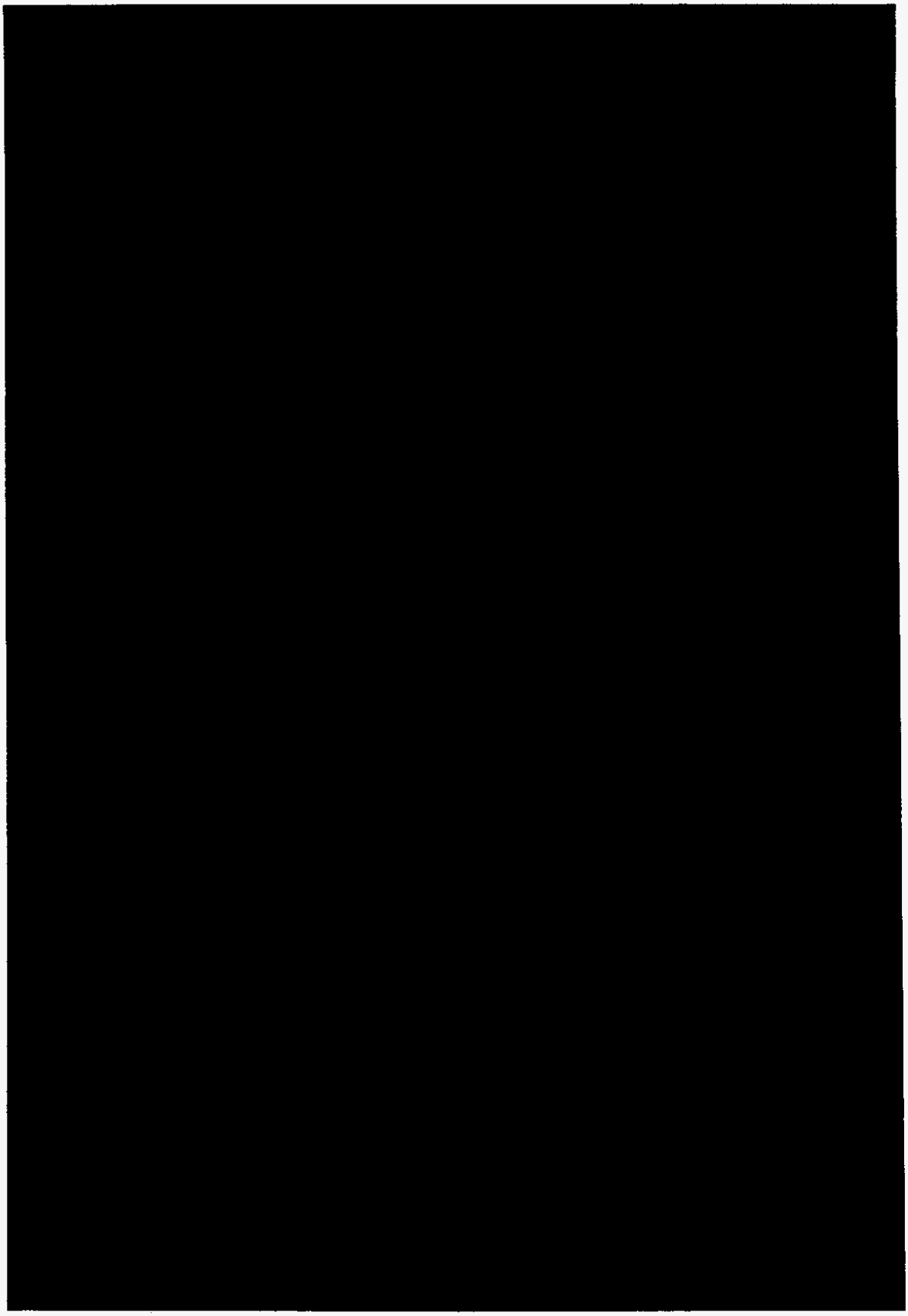


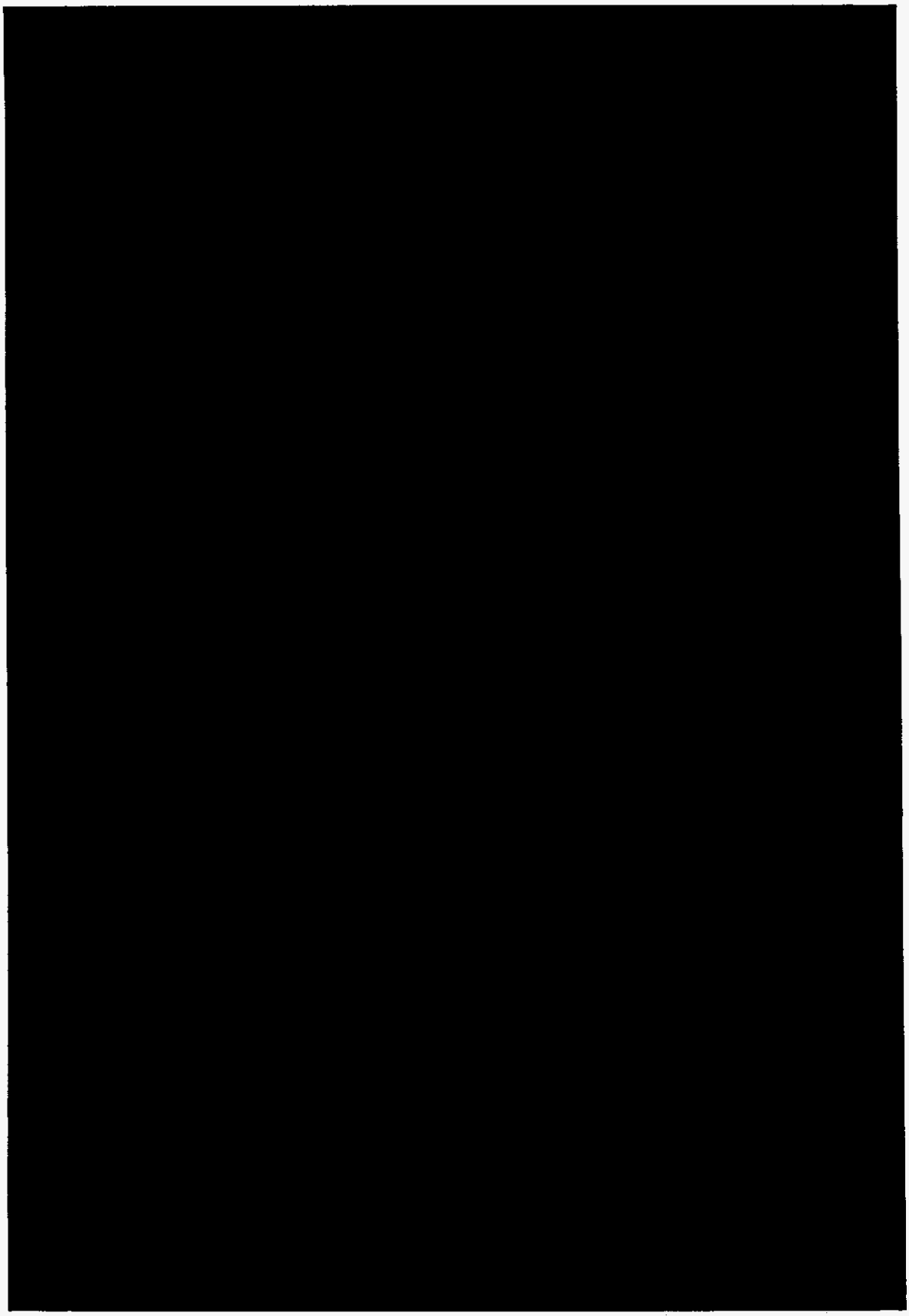


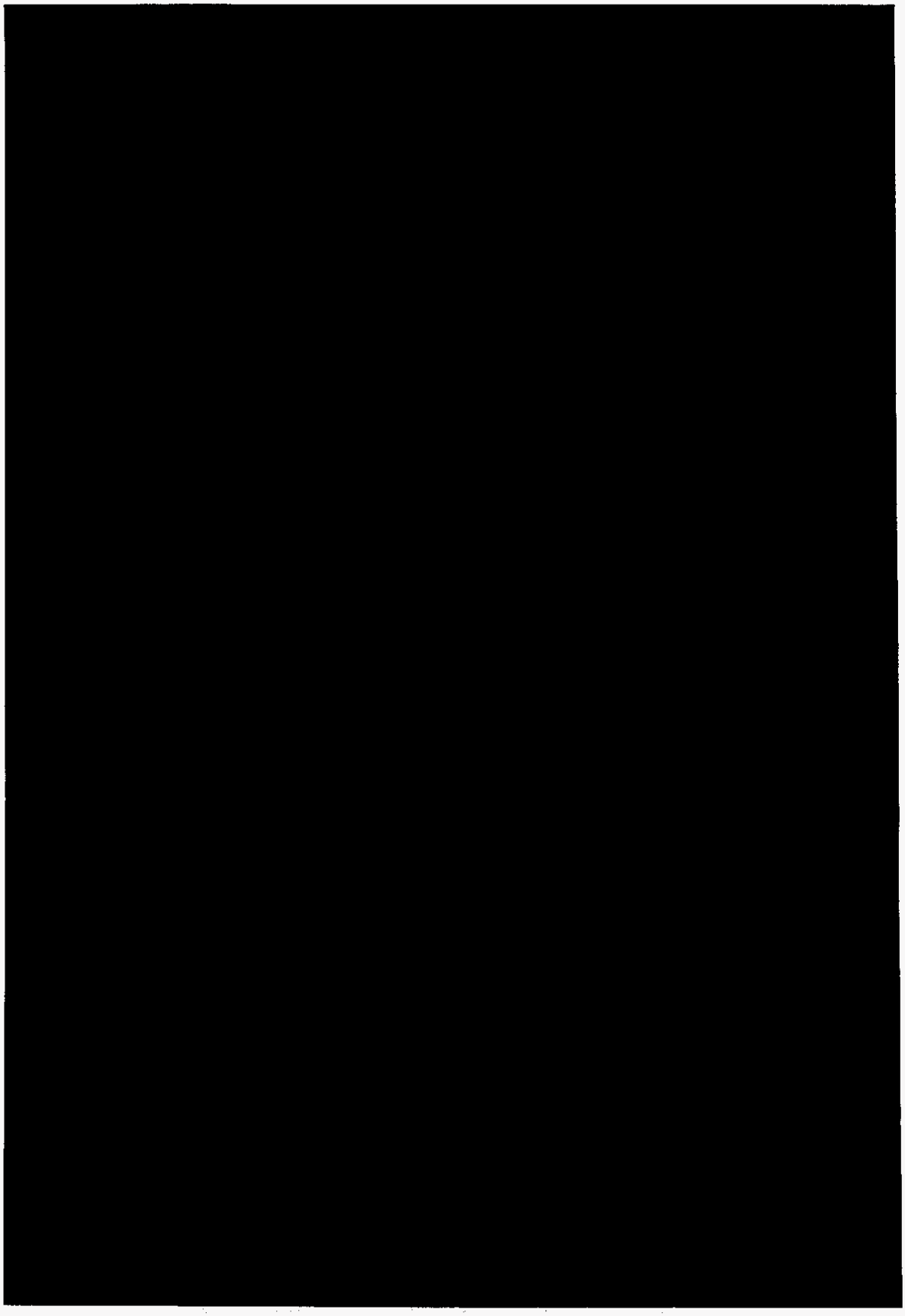


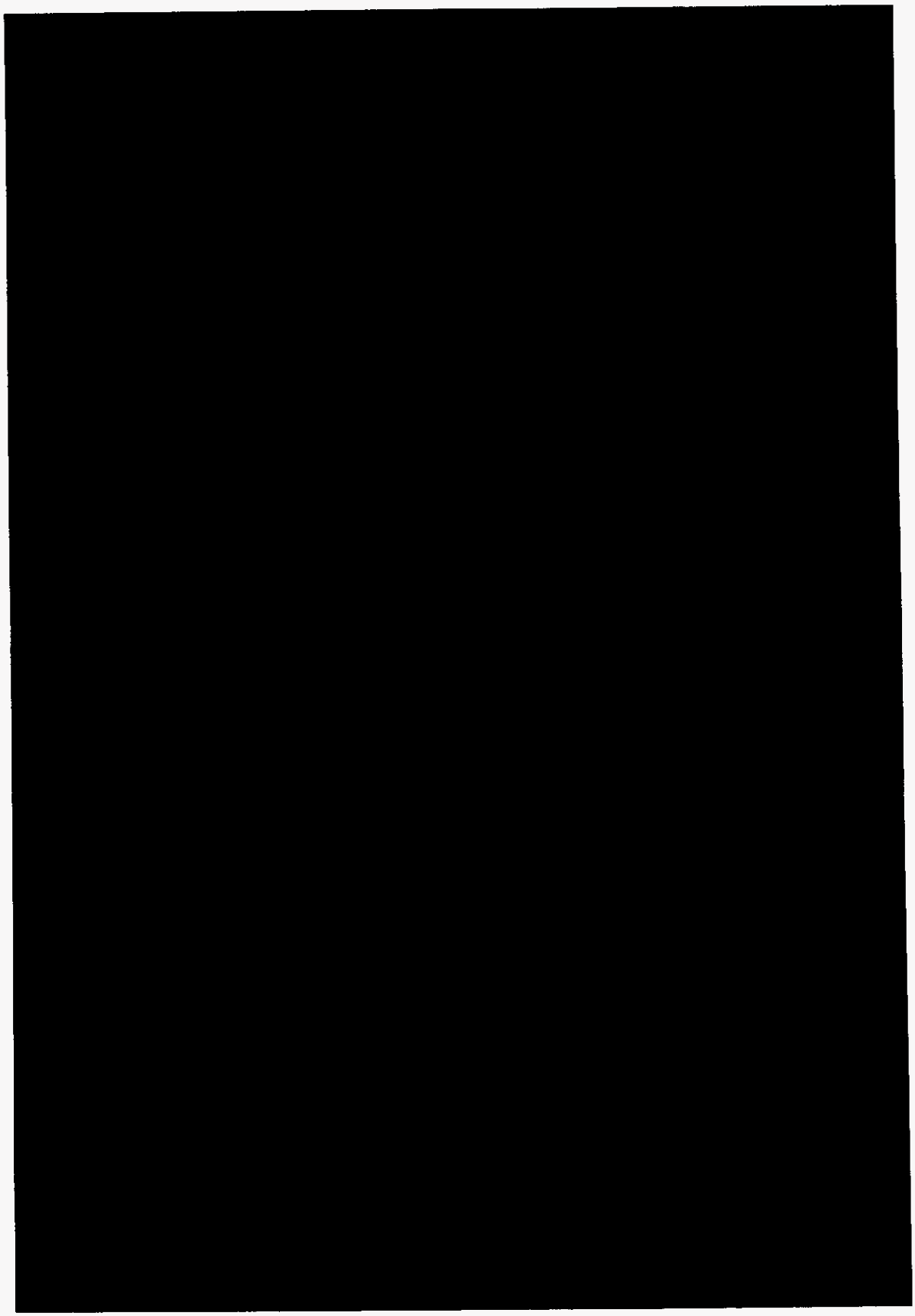


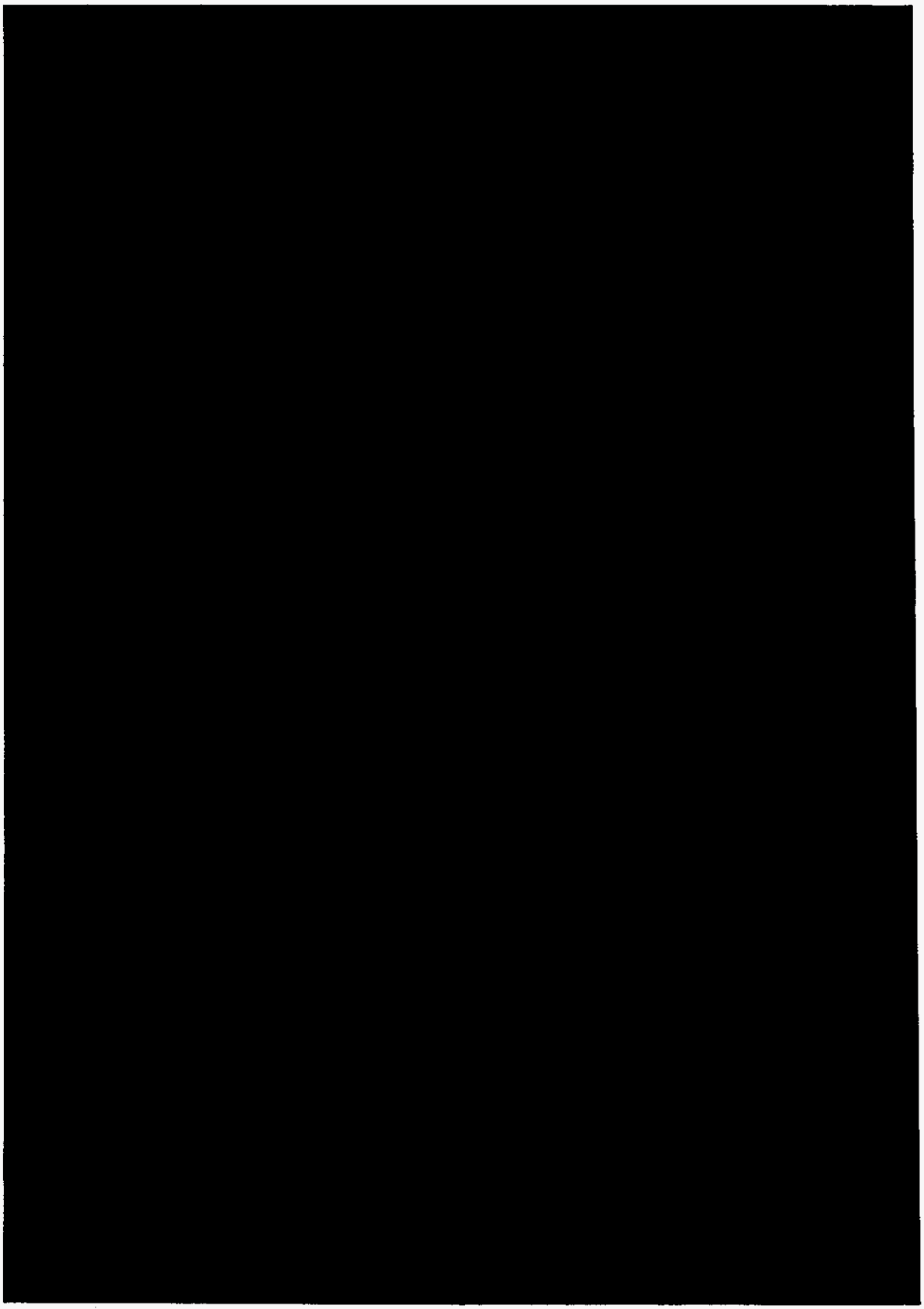


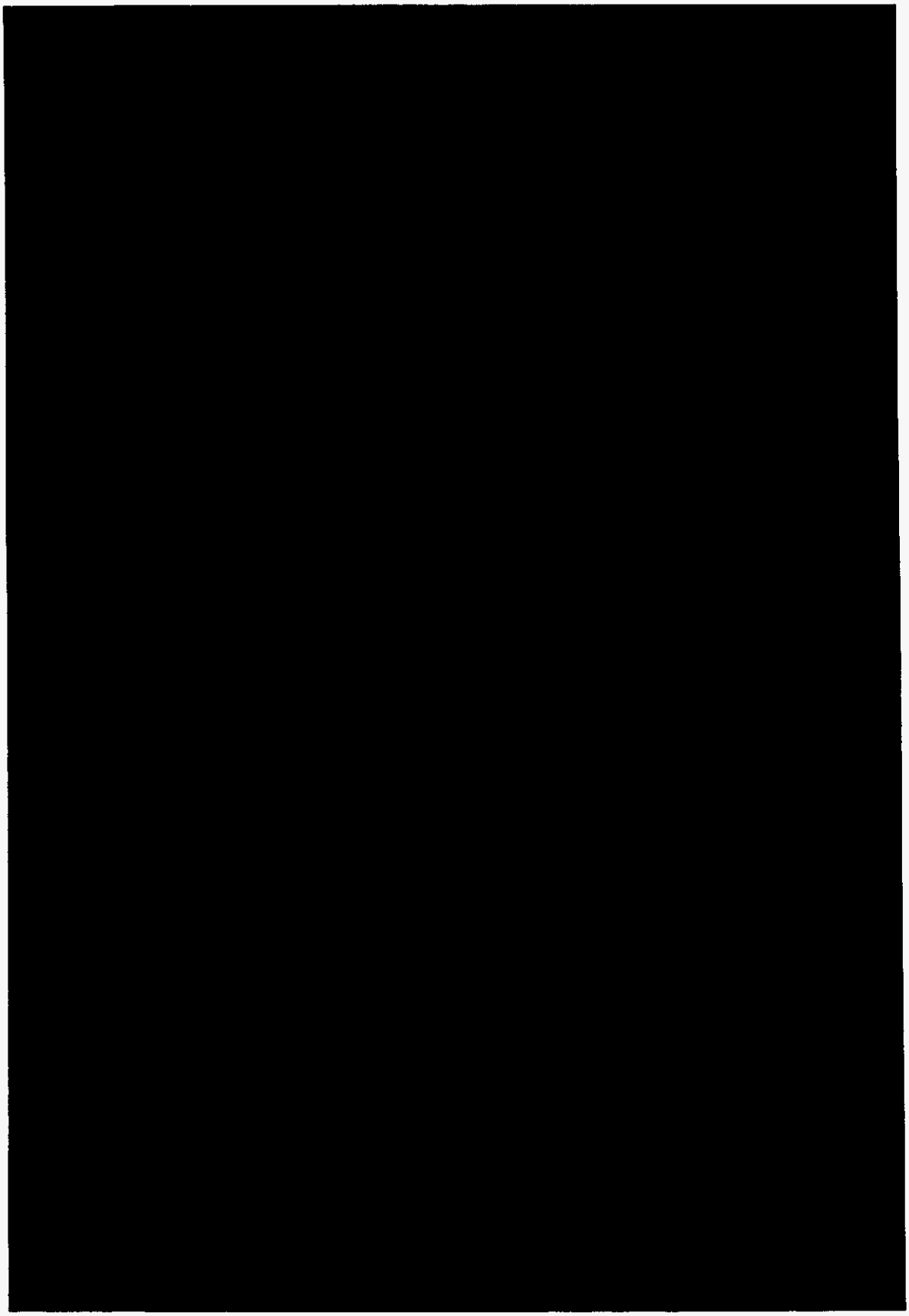


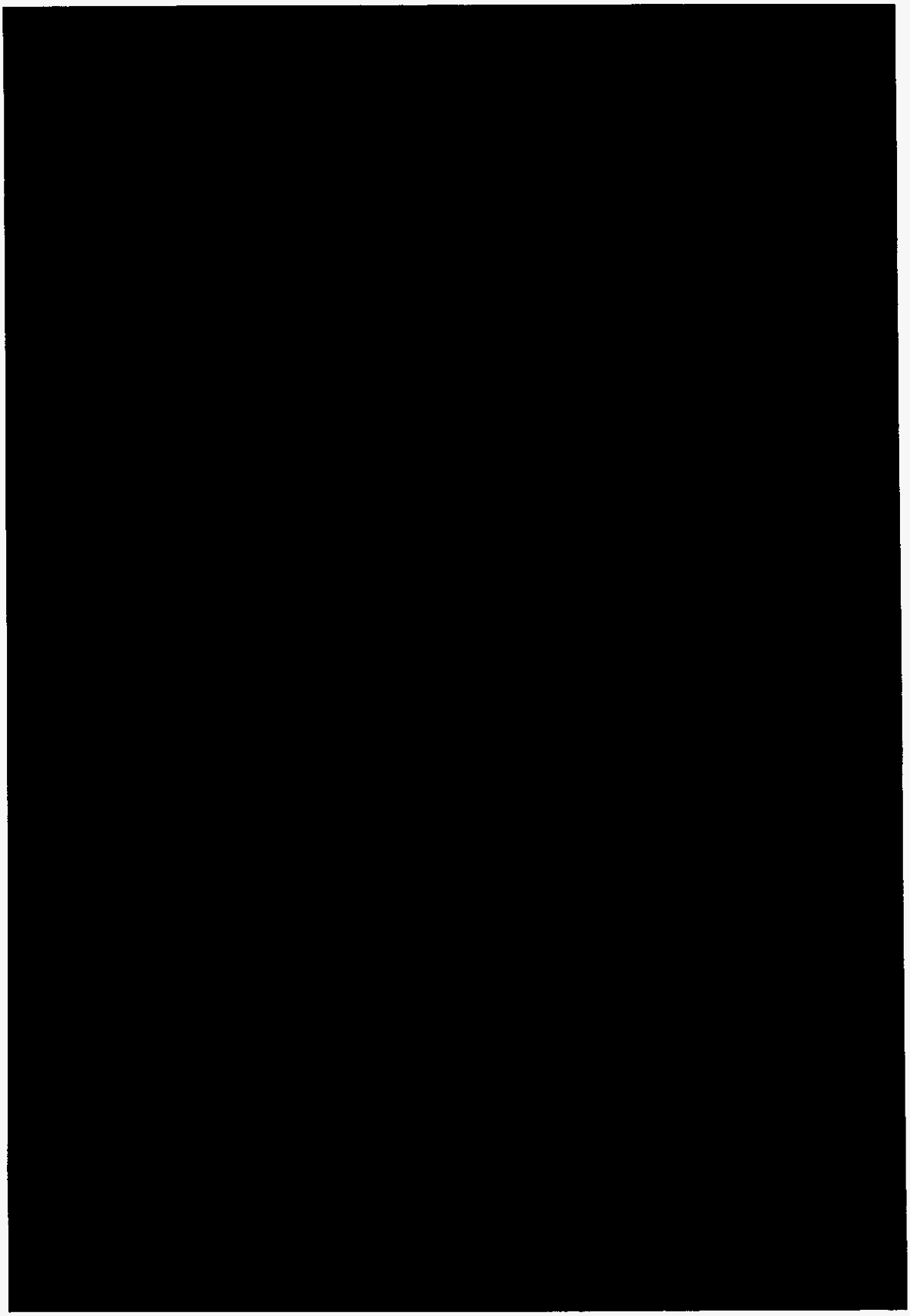


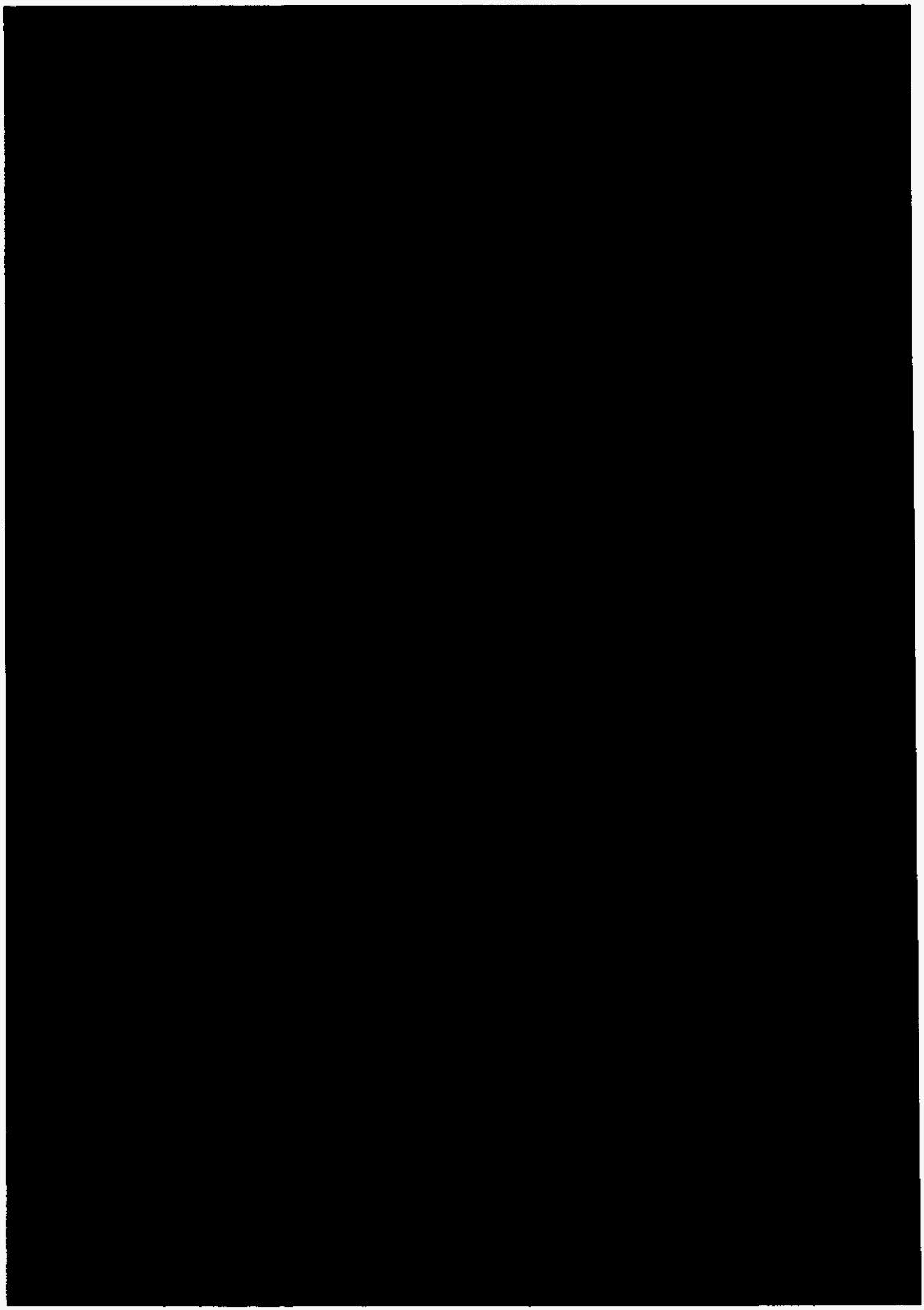


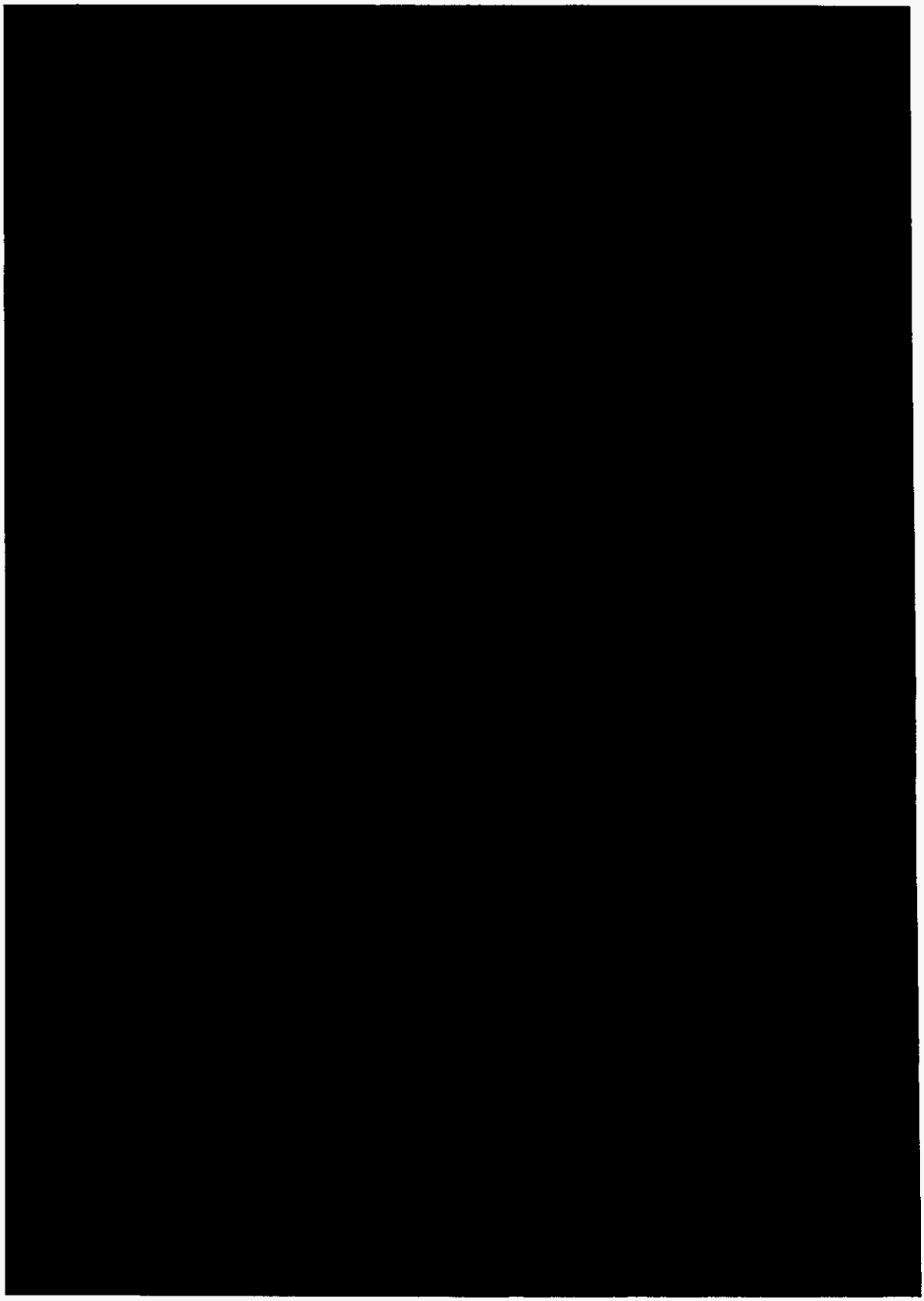


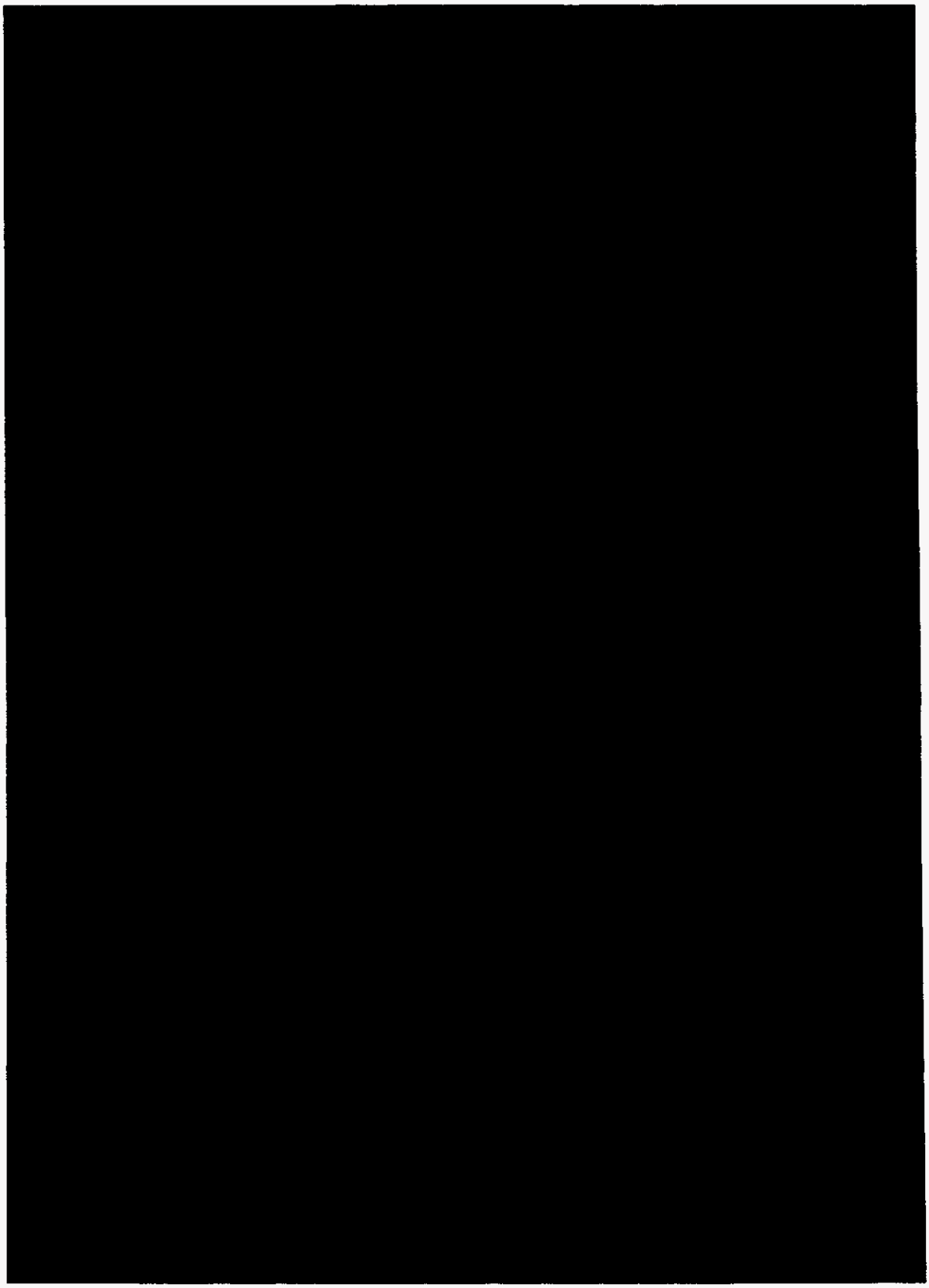


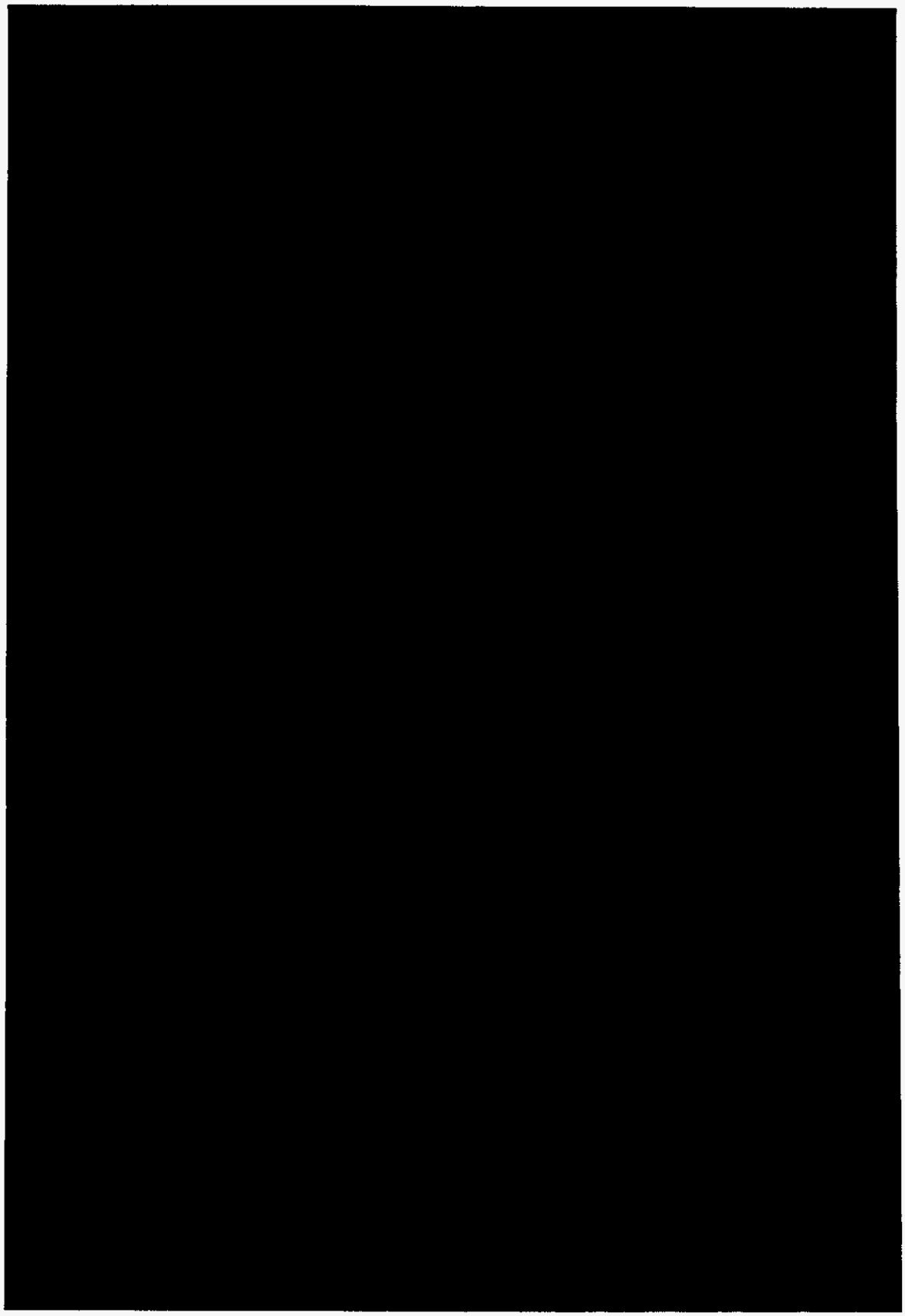


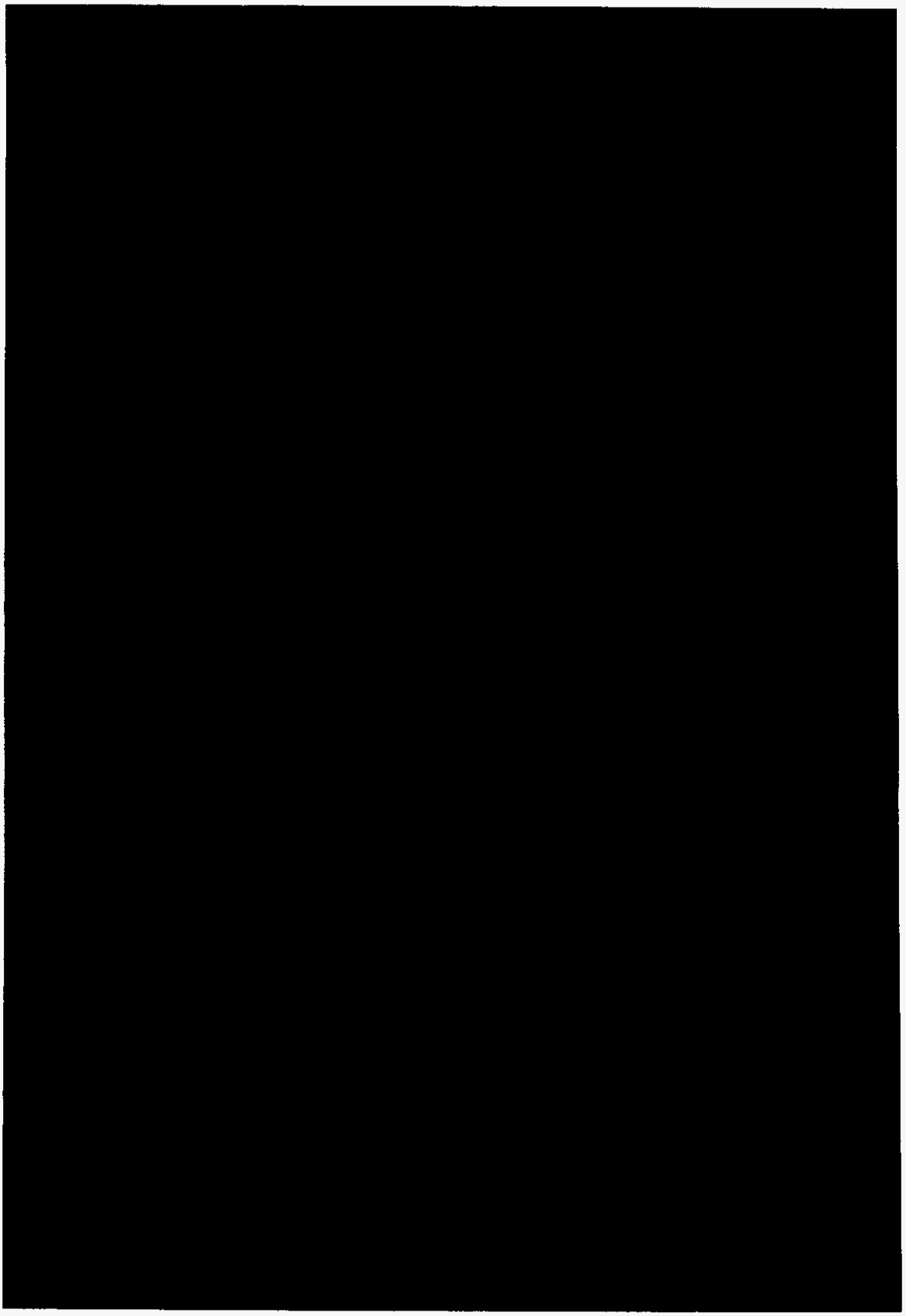


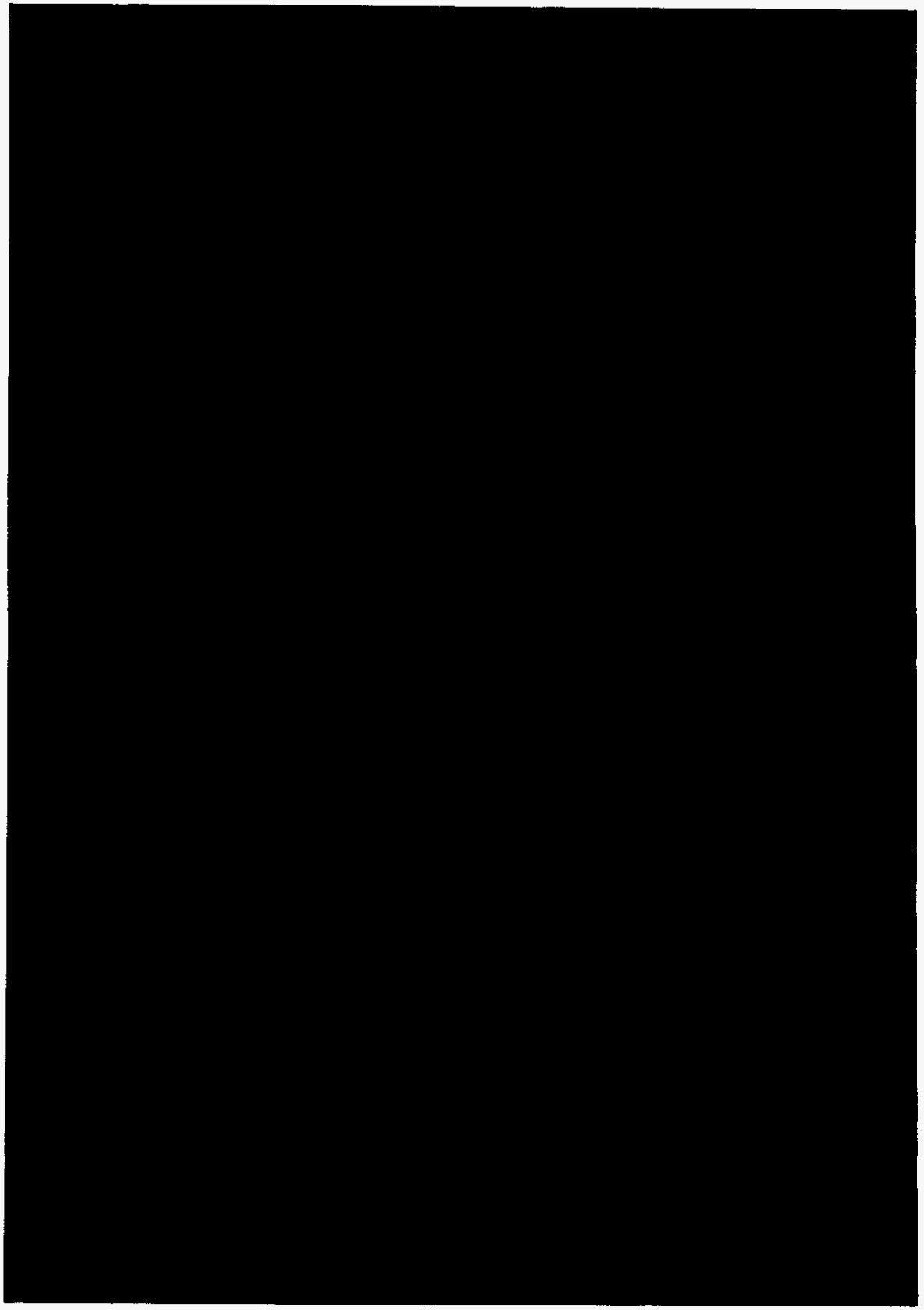


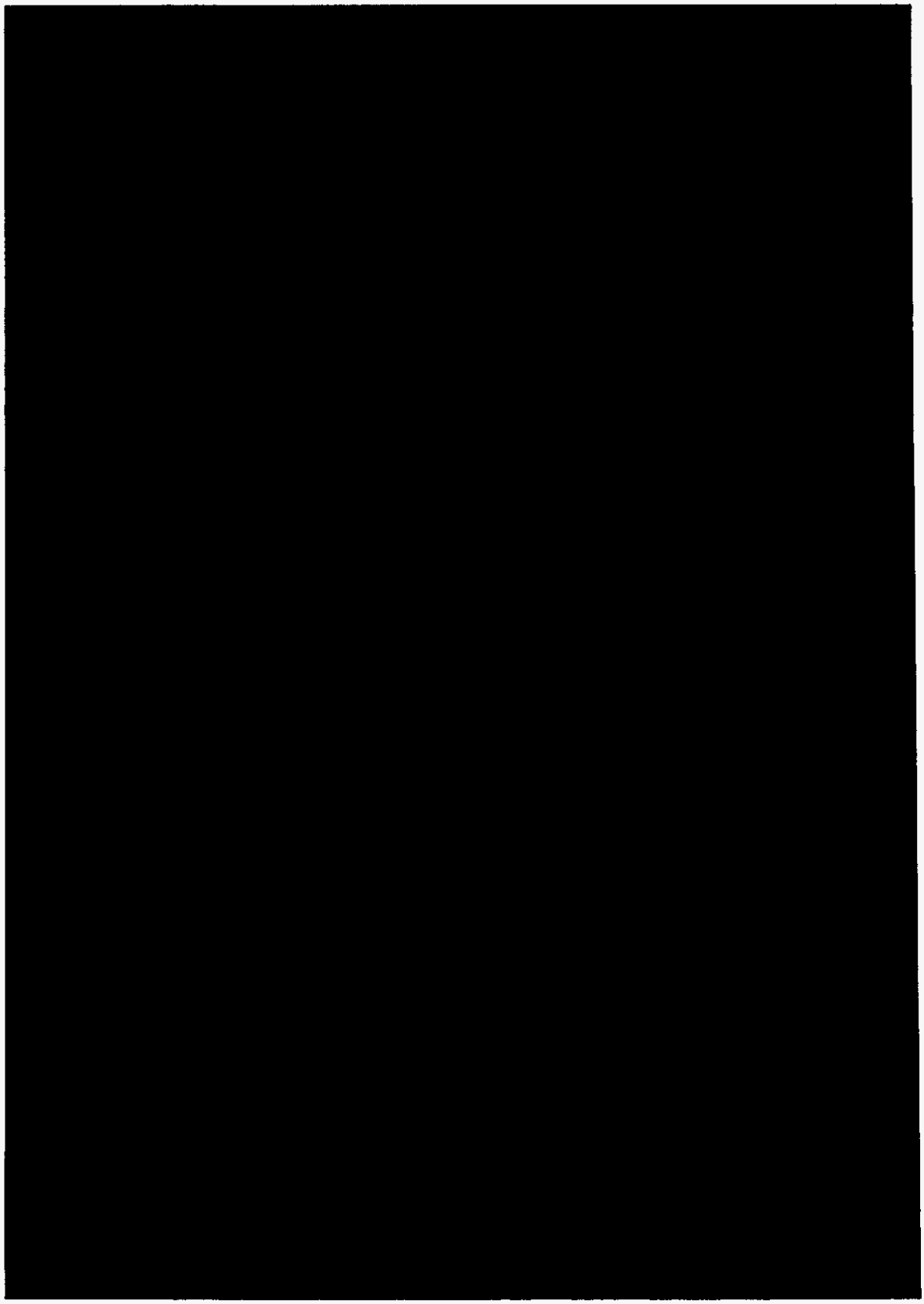


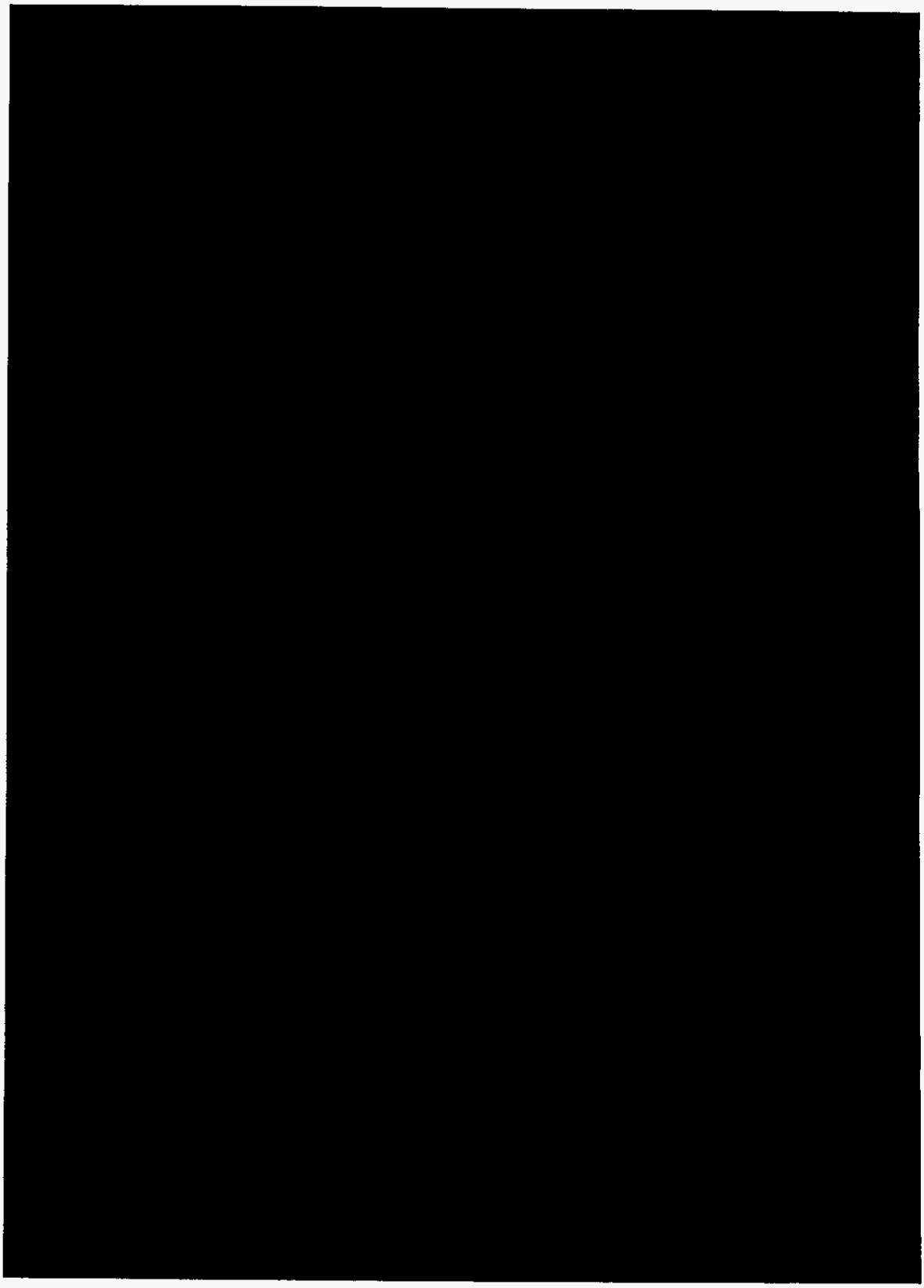


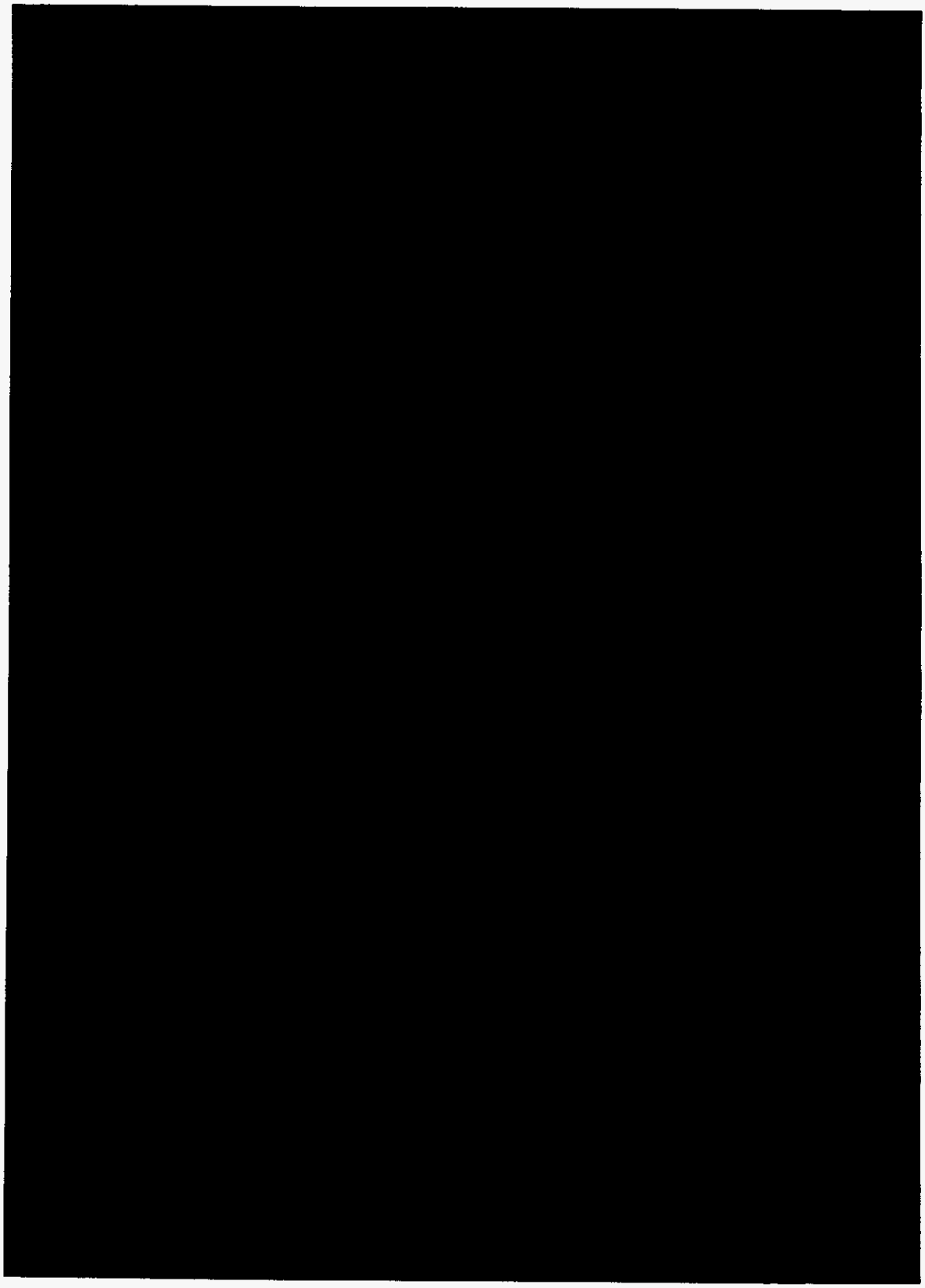


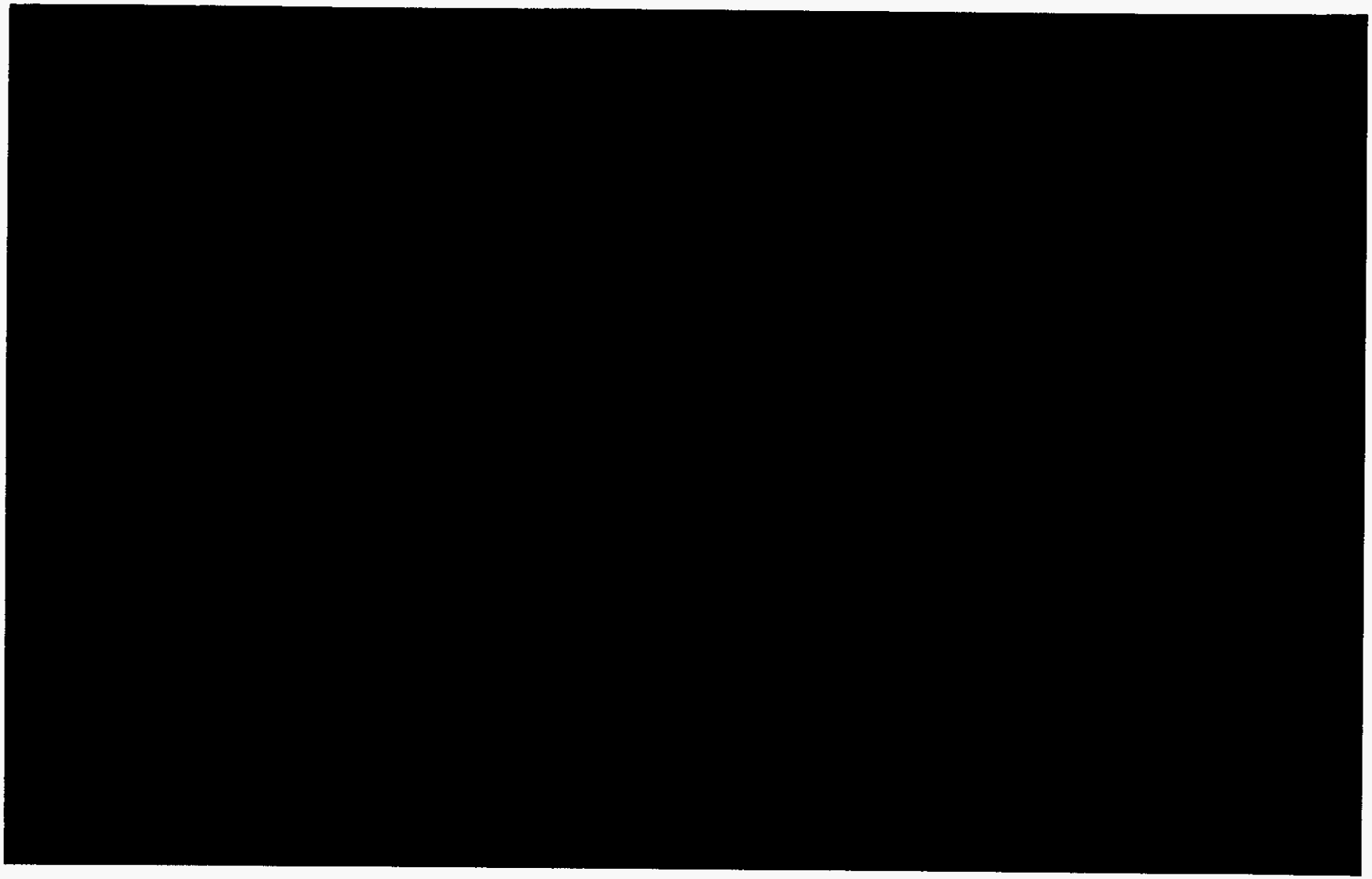


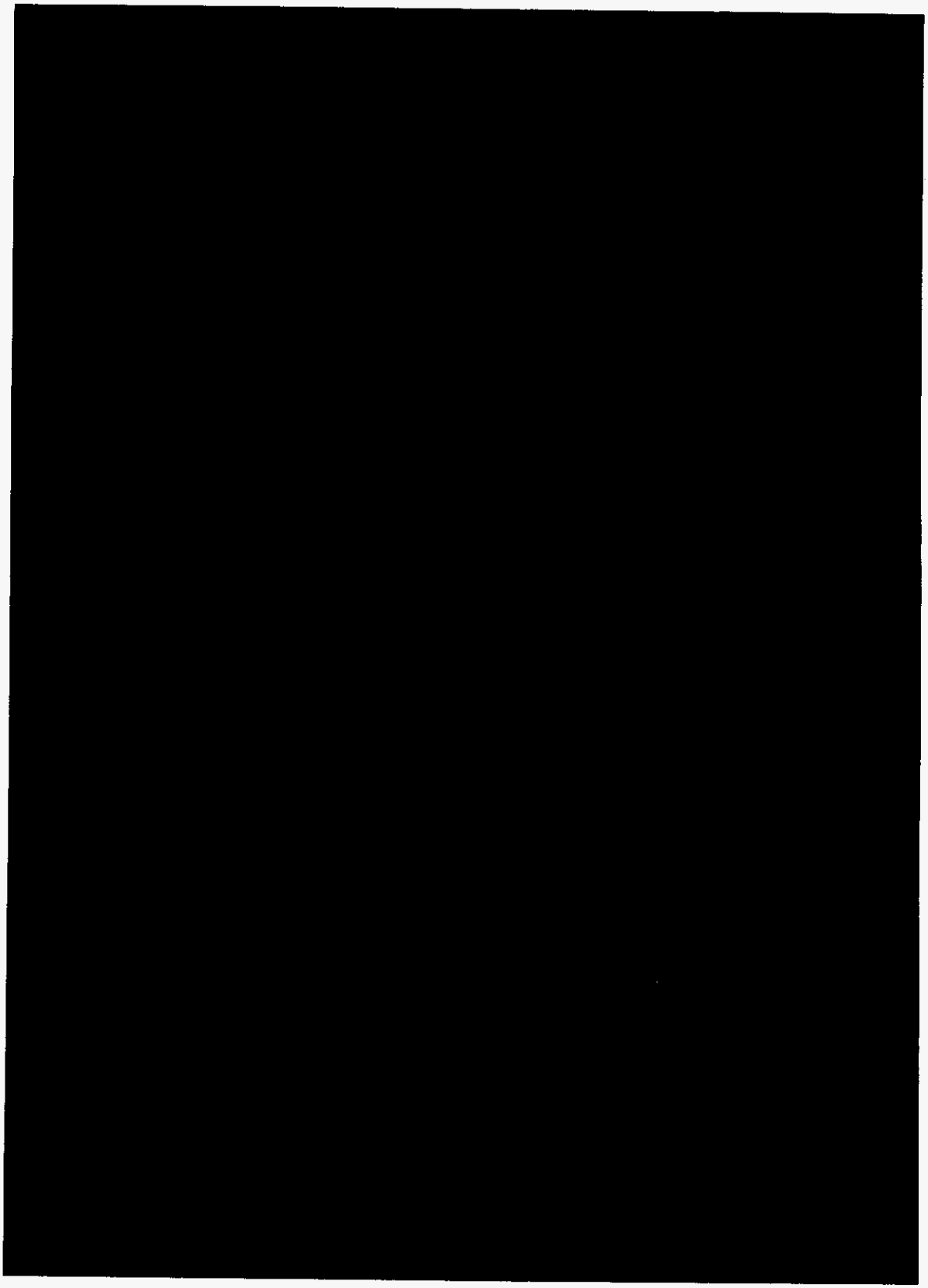












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT FRANKLIN UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 15
COMPANY/ F.P.+L.
WITNESS. T.L. Hartman (TLH-3)
DATE 11-08-04

TLH-3
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC. AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Southern Power Company, a Delaware corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203 (hereinafter referred to as "Southern Power" or "Seller") and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"**Affiliate**" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" means, with respect to any payment under Section 14.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"Agreement" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"**Alternate Delivery Point(s)**" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.5 or Section 5.6 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"**Alternate Resource(s)**" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.5 or Section 5.6.

"**Available Capacity**" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"**Billing Month**" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"Block 1 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 2 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 3 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 4 Mode" means any time a Schedule requests energy for any hour in an amount equal to the full amount of Contract Capacity and such capacity is greater than [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than the Contract Capacity but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block Mode" means either Block 1 Mode, Block 2 Mode, Block 3 Mode, or Block 4 Mode.

"Btu" means British Thermal Units.

"**Business Day**" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"**Buyer**" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Buyer Percentage" means 35.2 percent.

"**Central Prevailing Time**" or "**CPT**" means the local time at any point in Birmingham, Alabama.

"**Change in Law**" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"**Commercially Reasonable**" or "**Commercially Reasonable Efforts**" means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"**Contemporaneous Agreements**" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Harris Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Seller) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Scherer Unit No. 3 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Georgia Power Company and Gulf Power Company) and Buyer.

"**Contest**" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"**Contract Capacity**" means the lesser of: (i) 190 MW; or (ii) the Total Facility Capacity multiplied by the Buyer Percentage, or such other amount as expressly provided in this Agreement.

"**Contract Year**" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each 12 Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"**Day**" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"**Delivery Day**" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"**Delivered Energy**" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of: (i) energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule; and (ii) any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"**Delivered Energy Credit**" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

"**Delivery Excuse**" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); (iii) any directive from the applicable transmission provider

and/or control area operator to cease deliveries of energy from the Facility; (iv) SNG's failure to schedule or to deliver scheduled quantities of Gas to the Facility (but only if, for the period of such failure, Seller has complied with Section 9.1 and has utilized Commercially Reasonable Efforts to utilize available transportation capacity as required by Section 9.2.1 to satisfy Buyer's Schedule); or (v) a circumstance described in Section 9.2.7 and/or Section 9.3.2.

"**Delivery Point**" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"**Effective Date**" has the meaning set forth in the introductory paragraph hereof.

"Electric Metering Equipment" means electric meters and associated equipment, including metering transformers and back-up meters.

"**EFMH**" or "**Equivalent Force Majeure Hour**" shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.5.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"**EUH**" or "**Equivalent Unavailable Hour**" shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"**Event of Default**" has the meaning set forth in Section 16.1.

"**Facility**" means Seller's Gas fired combined cycle electric generating unit known as Plant Franklin Unit No. 1 (as may be modified) and all appurtenant facilities, located near Smiths, Alabama which directly interconnects to the Georgia Integrated Transmission System, or such other resource designated as the Facility pursuant to Section 3.3.

"Facility Delivery Point" means the substation where the Facility interconnects to the Georgia Integrated Transmission System (or other applicable transmission system) at the transmission system voltage.

"**FERC**" means the Federal Energy Regulatory Commission, or any successor to its functions.

"Florida Interface" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"Force Majeure Capacity" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Force Majeure Event. Force Majeure Capacity shall be calculated as follows:

Force Majeure Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = Buyer Percentage * Adjusted Total Unaffected Capacity

Adjusted Total Unaffected Capacity = the lesser of TCUFM or 540 MW

TCUFM = Total Capacity Unaffected by Force Majeure = Total Facility Capacity – TAC

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Force Majeure Event.

"**Force Majeure Event**" has the meaning set forth in Section 15.1.

"**Gas**" means natural gas.

"**Georgia Integrated Transmission System**" means the electric transmission systems owned individually by Georgia Power Company, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia, and operated as an integrated transmission system, as well as any successor transmission system.

"**Government Agency**" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

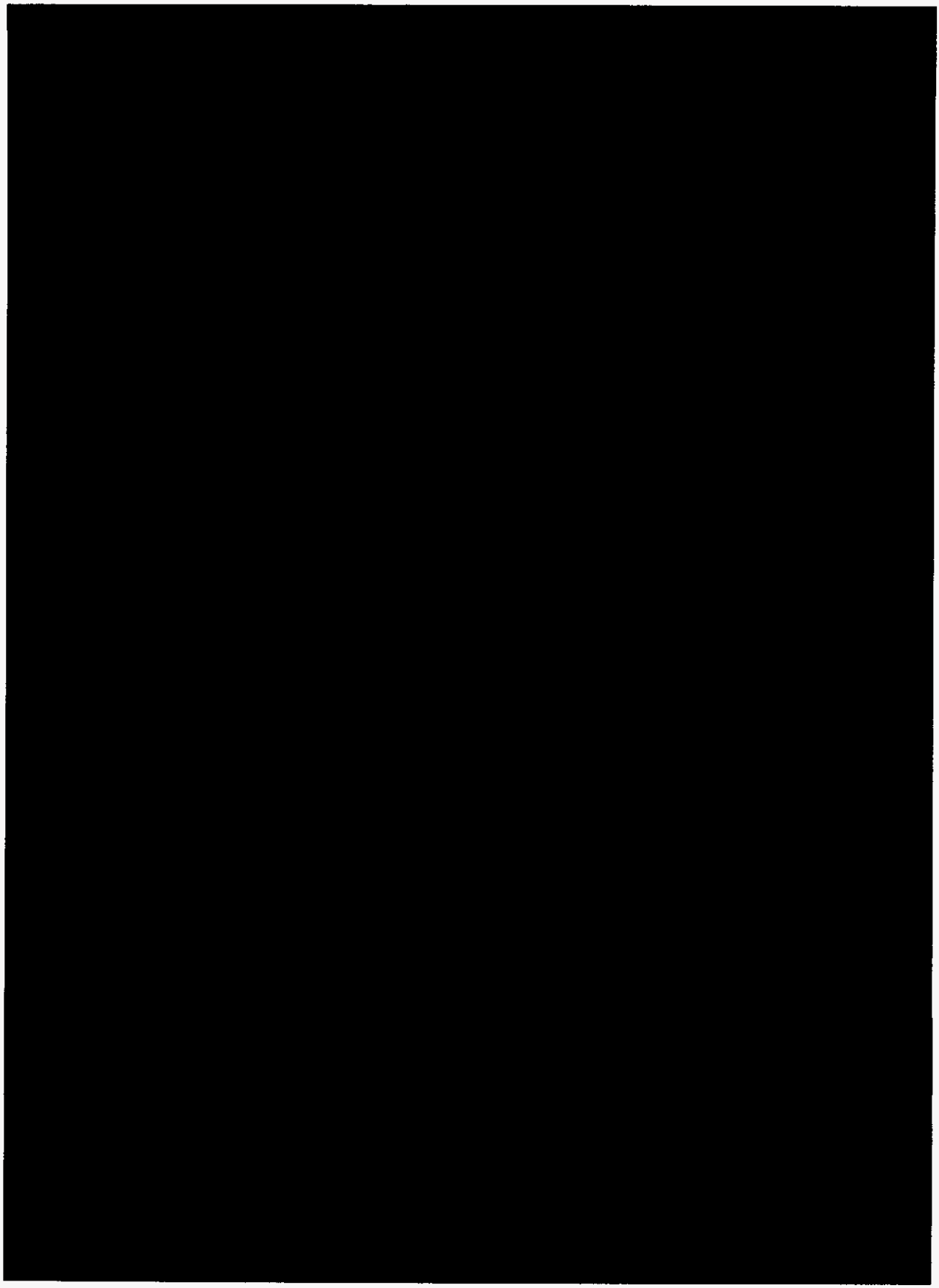
"**Governmental Approval**" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"**Guarantor**" has the meaning set forth in Section 16.1.

"**Guaranty**" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 20.

"**Imaged Agreement**" has the meaning set forth in Section 21.17.

"**Increased Generation Costs**" [redacted]



"**kW**" means kilowatt(s).

"**kWh**" means kilowatt hour(s).

"**Law**" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"**Maintenance Outage**" has the meaning set forth in Section 4.2.

"Major Maintenance" means the performance of a hot gas path inspection for the combustion turbines at the Facility.

"**Major Maintenance Off-Peak Performance Period**" means any Off-Peak Performance Period in which Major Maintenance occurs.

"**MMBtu**" means one million Btu.

"**Month**" means a calendar month.

"**Monthly Capacity Payment**" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"**Monthly Energy Payment**" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"**Monthly Fuel Transportation Payment**" means the payment for fuel transportation to be made by Buyer to Seller pursuant to Section 6.4.

"**Monthly Start Payment**" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"**Moody's**" has the meaning set forth in Section 19.1.

"**MW**" means megawatt(s).

"**MWh**" means megawatt hour(s).

"**NERC**" means the North American Electric Reliability Council, or any successor to its functions.

"**Normal Off-Peak Performance Period**" means any Off-Peak Performance Period in which Major Maintenance does not occur.

"**OATT**" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Off-Peak Performance Period" means the period of time consisting of all hours during the Months of October, November, December, January, February, March and April in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Off-Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Off-Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"**Operating Committee**" has the meaning set forth in Section 4.5.

"**Operating Procedures**" has the meaning set forth in Section 4.4.

"**Outage**" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure and during Scheduled Outages and Maintenance Outages. An Outage does not include those times that the Facility's capability is reduced (in whole or in part)

due to a Force Majeure Event or a Delivery Excuse. In addition, an Outage shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Outage Capacity" means, for any hour in which an Outage occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Outage. Outage Capacity shall be calculated as follows:

Outage Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = Buyer Percentage * Adjusted Total Unaffected Capacity

Adjusted Total Unaffected Capacity = the lesser of TCUO or 540 MW

TCUO = Total Capacity Unaffected by Outage = [the sum of: (A) the lesser of: (i) Total Facility Capacity; or (ii) 540 MW; and (B) Unused Excess Capacity] – TAC

Unused Excess Capacity = to the extent it is positive, the difference of TCUFM as determined under the definition of "Force Majeure Capacity" hereunder, less 540 MW

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Outage.

"Peak Performance Period" means the period of time consisting of all hours during the Months of May, June, July, August and September in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Performance Period" shall mean either a Peak Performance Period or an Off-Peak Performance Period.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Franklin located near Smiths, Alabama, which currently consists of the Facility and a combined cycle electric generating unit known as Plant Franklin Unit No. 2 and all appurtenant facilities, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal.* In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance

standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"**S&P**" has the meaning set forth in Section 19.1.

"**SNG**" means Southern Natural Gas Company.

"**Schedule**" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"**Schedule Start**" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled (in any Block Mode).

"**Scheduled Energy**" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement.

"**Scheduled Outage**" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"**Scheduling Parameters**" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"**Seller**" has the meaning set forth in the introductory paragraph hereof.

"**Service Commencement Date**" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"**Southern Company**" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"Southern Company Transmission" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"Southern Company Transmission System" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"Southern Power" has the meaning set forth in the introductory paragraph.

"**Taxes**" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"**Term**" has the meaning set forth in Section 2.1.

"Total Facility Capacity" means, for each Contract Year, the generating capability of the Facility as declared by Seller under Article 8.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.5.1 in response to the Outage causing Outage Capacity to exist, less the

Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term"). Provided, however, the Service Term shall be extended through December 31, 2017 if: (i) Buyer provides Seller with written notice of its desire to extend the Service Term in this manner on or before January 31, 2010 ("Extension Notice"); and (ii) [redacted] If Buyer timely provides Seller the Extension Notice but the Parties are unable to agree on such [redacted] and/or a related amendment by December 31, 2010, the Service Term shall be extended through May 31, 2017.

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 Effect of Termination. Subject to the exercise of a non-defaulting Party's rights under Section 14.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 Sale and Purchase of Capacity. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 Sale and Purchase of Energy. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

3.3 Change of the Facility. At any time during the Term, Seller may provide notice to Buyer that it desires to change the generating resource that constitutes the Facility under this Agreement; provided, however, such resource shall be a Gas-fired resource. Provided further, the Facility shall not be changed under this Section 3.3 more often than once every [redacted]

With any such notice, Seller shall identify the generating resource that will be the proposed new Facility, the date that Seller desires for such change to be effective ("Desired Date of Facility Change"), and the anticipated time during which such resource shall provide Contract Capacity and associated energy under this Agreement ("Facility Term"). Seller shall provide Buyer such notice no later than [redacted] prior to the Desired Date of Facility Change. Within 15 Days after receipt of Seller's notice, Buyer and Seller shall confer to discuss the proposed Facility change and any amendment(s) to this Agreement that may be necessary to effect such change. Seller and Buyer agree that any such Facility change(s) shall be subject to the mutual consent of the Parties; provided, however, Buyer shall not unreasonably withhold its consent to a proposed Facility change(s) or reasonable amendment(s) necessary to effect such change. For purposes hereof, it shall be unreasonable for Buyer to withhold its consent to a proposed Facility change by Seller (or associated amendment) if such change and/or amendment would not be expected to result in: (i) an increase in Buyer's costs during the Facility Term as compared to the then current Facility; or (ii) a decrease in Facility reliability during the Facility Term as compared to the then current Facility. Any such change in the Facility shall be expressly conditioned upon Buyer's ability to obtain transmission service during the Facility Term that has a firmness that is the same or greater than, and has a cost that is equal to or less than, the service Buyer has procured from the then current Facility; provided that Buyer shall afford Seller reasonable opportunity to offset any higher cost such that Buyer would be able to obtain such service at a cost equal to the cost of service already procured by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"); [redacted] Within 30 Days after receiving Seller's proposed schedule for Scheduled Outages, Buyer may request, in writing, that Seller reschedule any such Scheduled Outages. Following receipt of such request, Seller shall attempt to coordinate among Buyer and other parties purchasing capacity and energy from the Facility in order to reschedule such Scheduled Outages; provided, however, Seller shall have sole discretion to decline to accommodate any request to reschedule Scheduled Outages. Following receipt of Buyer's request, Seller shall inform Buyer as to whether it will accommodate Buyer's request and, if so, shall further advise Buyer of the good faith estimated costs that will be incurred by Seller in connection with accommodating the request of Buyer to reschedule the Scheduled Outages. Buyer shall then within 14 Days of the receipt of the estimated costs provided by Seller determine whether Seller should reschedule the Scheduled Outages. Without regard to any prior estimate, Buyer shall reimburse Seller for all Commercially Reasonable costs related to such change in schedule if Seller makes such change. Prior to or during any Contract Year, Seller may reschedule any Scheduled Outages in accordance with Prudent Industry Practices.

4.2 [redacted]



4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than 6 months before the Service Commencement Date. Such Operating Procedures shall be completed no later than 30 Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages, and hours of Delivery Excuse.

4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating

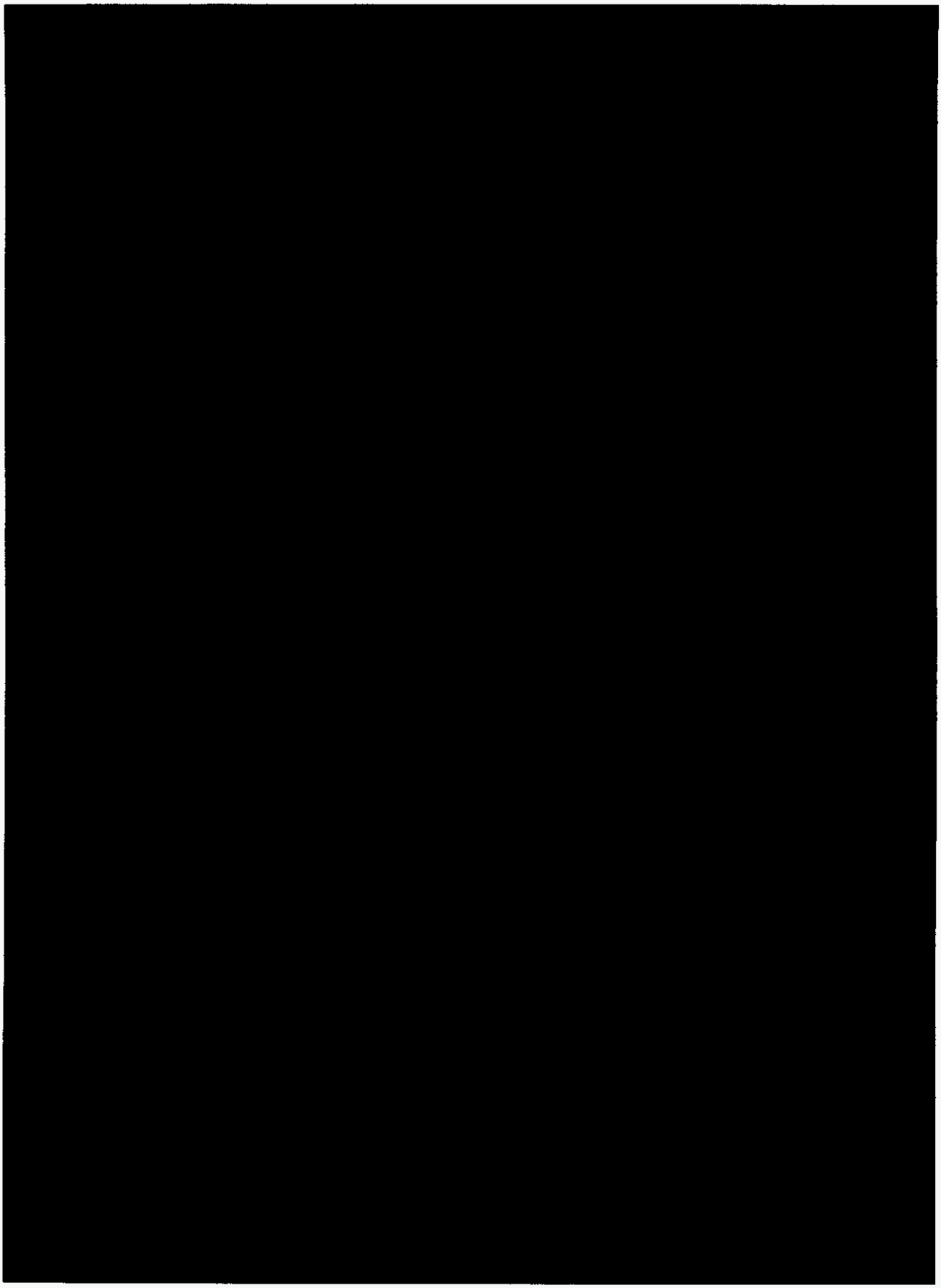
Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone) and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

[redacted]

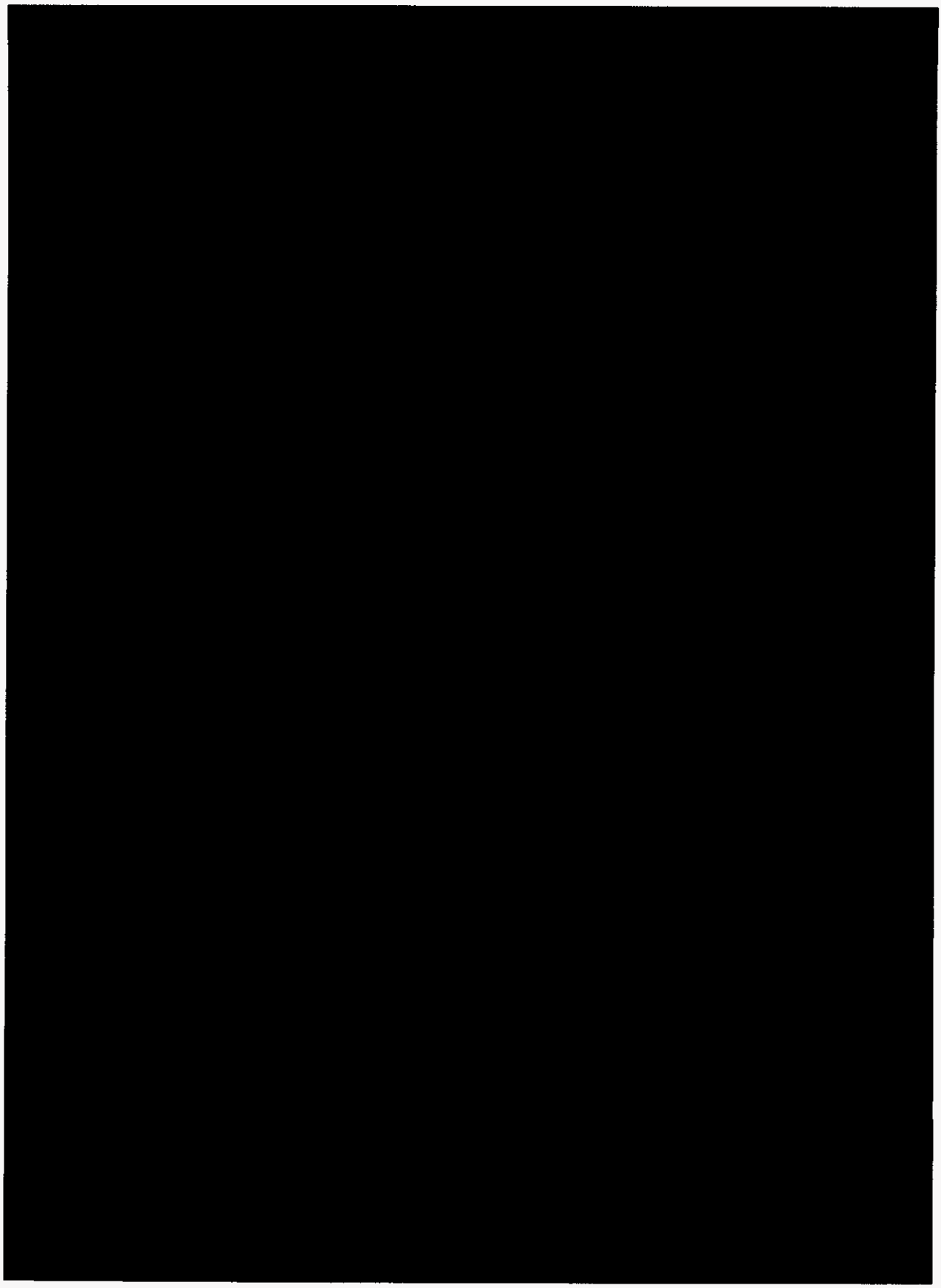


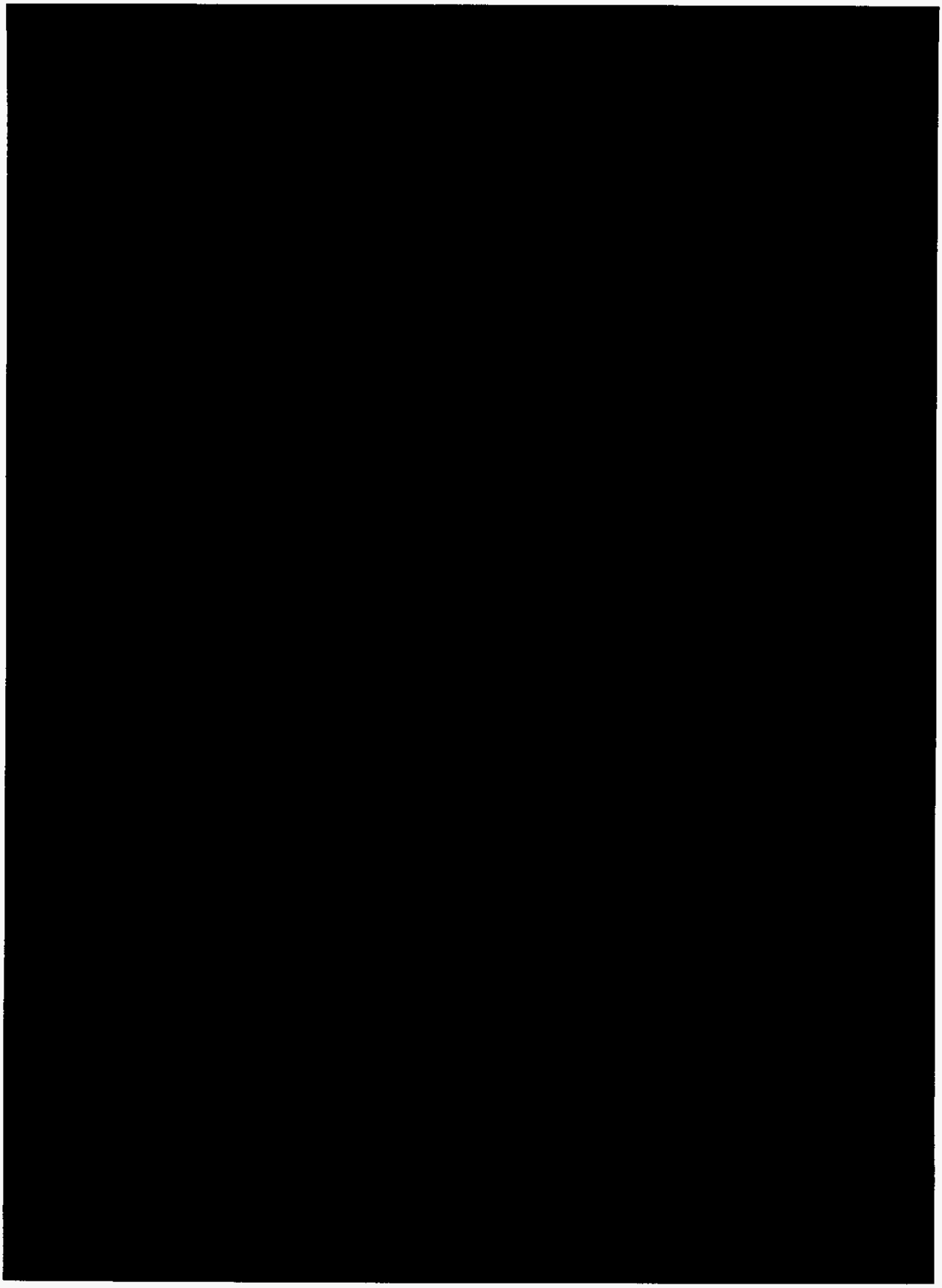
5.2 Transmission and Scheduling Requirements. Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

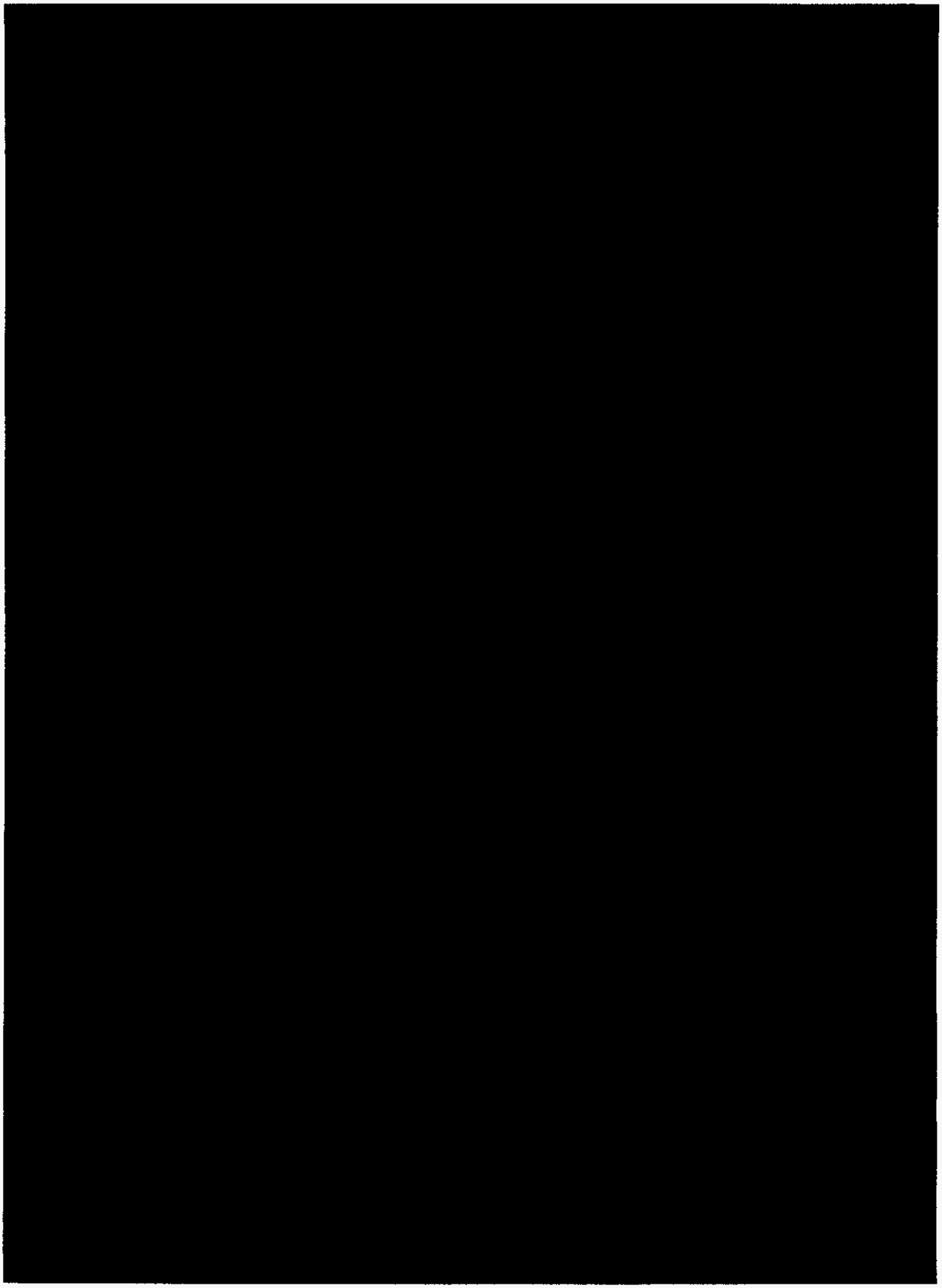
5.3 Costs and Expenses. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

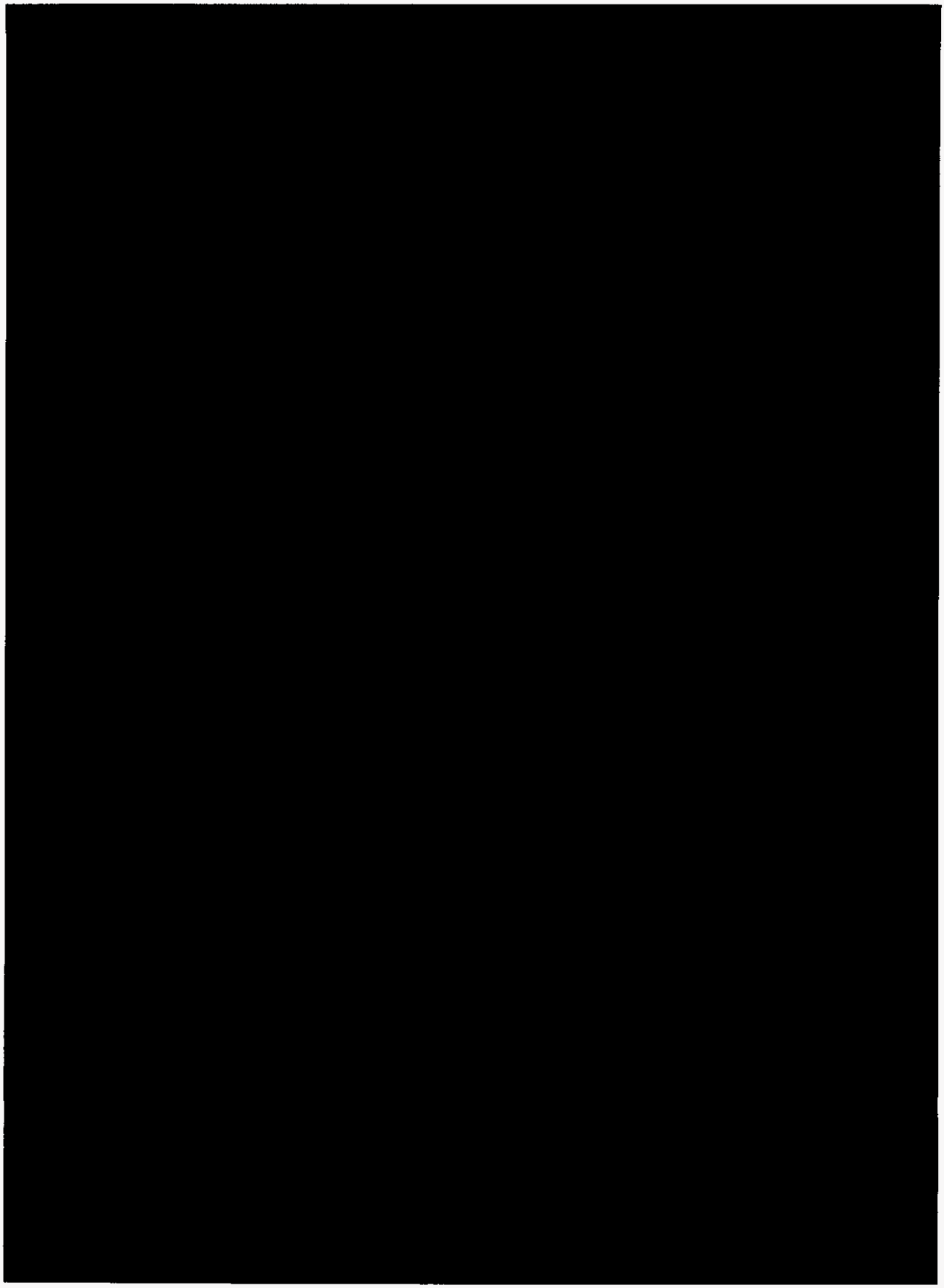
5.4 Delivery of Energy. Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.5 [redacted]









[redacted]

5.7 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.8 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.9 Force Majeure Event.

5.9.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.5 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.9.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.10 Outages and Unavailable Capacity.

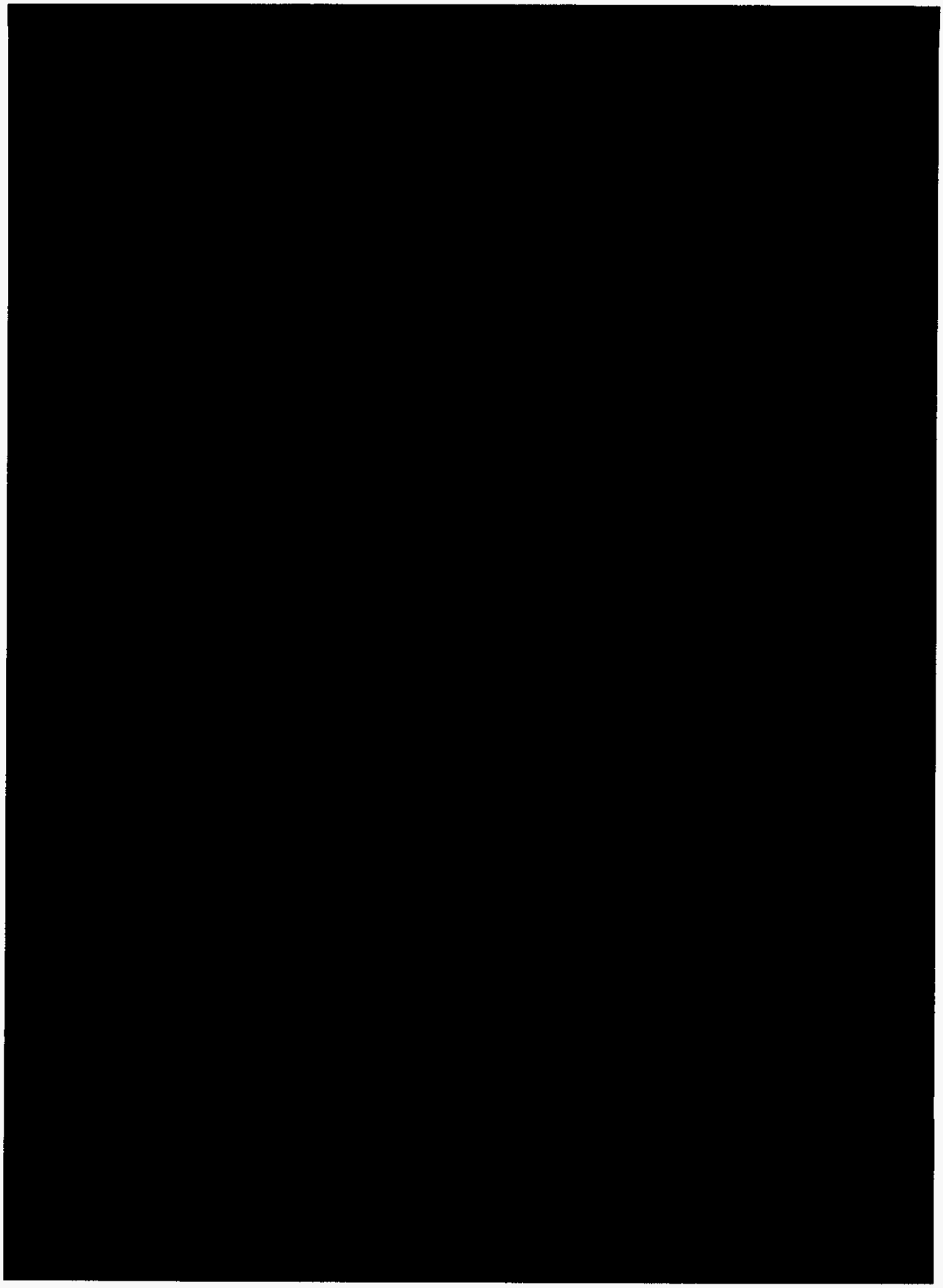
5.10.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Outage that is expected to result in Outage Capacity and the estimated duration of such Outage; (ii) the cessation of such Outage; and (iii) if requested by Buyer within 30 Days after the Outage and if known to Seller, the cause of such Outage.

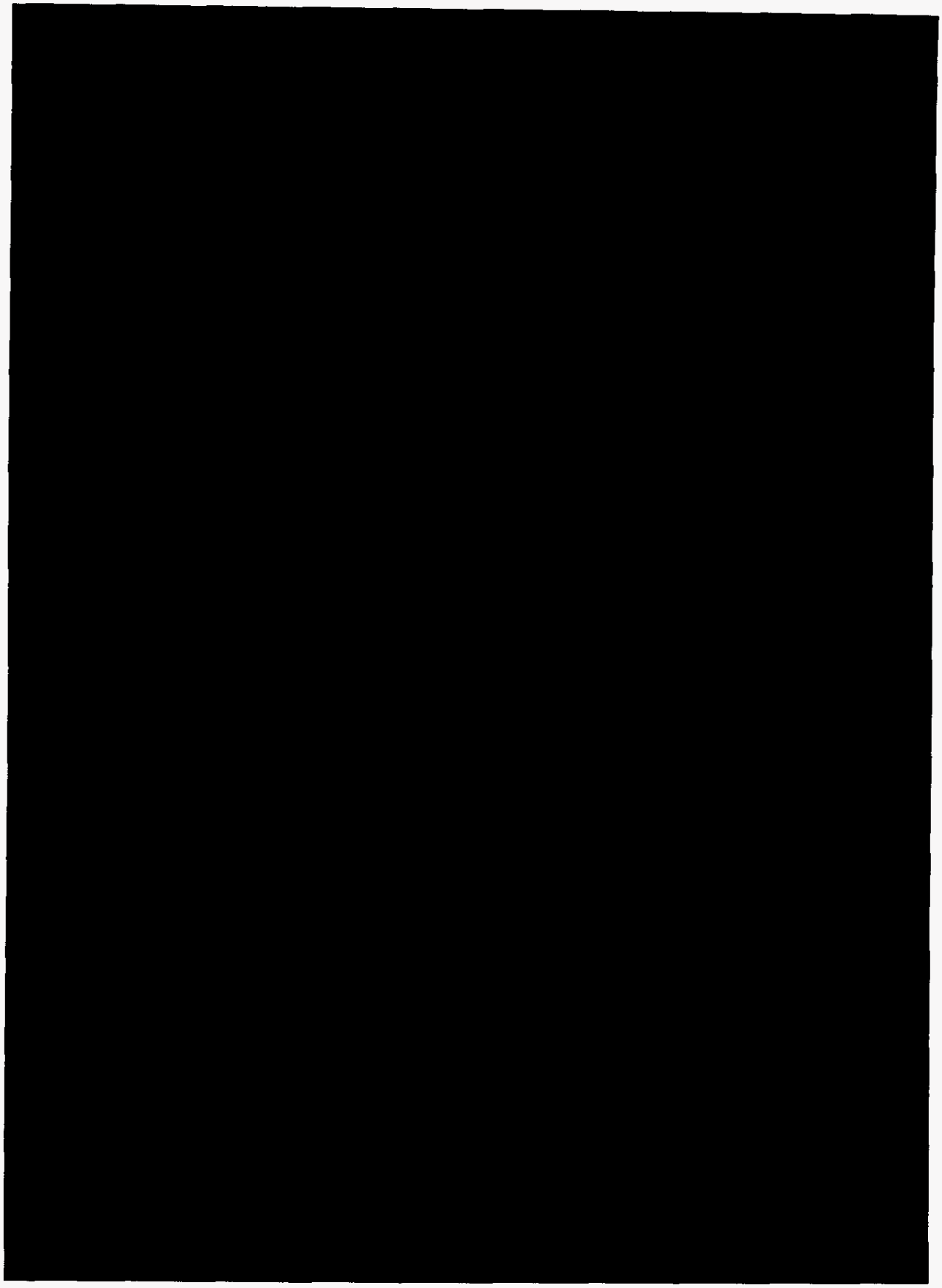
5.10.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall be [redacted]

5.11 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive, or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.12 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.13 [redacted]





[redacted]

ARTICLE 6

PAYMENTS

6.1 Capacity Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 Energy Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 Start Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Fuel Transportation Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Fuel Transportation Payment. The calculation of the Monthly Fuel Transportation Payment is set forth in Section 9.2.2.

6.5 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., an Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third

party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] Days after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 190 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same

extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate, and include any and all documentation of such Total Cost provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 190 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted] Buyer shall notify Seller of such election within 3 Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted] MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted] MW, Seller shall be entitled to either: [redacted]

[redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery

Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

[redacted]

[redacted]

ARTICLE 8

TOTAL FACILITY CAPACITY AND COMMENCEMENT OF SERVICE

8.1 Declaration of the Total Facility Capacity. Through notice to Buyer, Seller shall declare the Total Facility Capacity for each Contract Year pursuant to the procedures set forth in Section 8.2.

8.2 Declaration Prior to Each Contract Year.

8.2.1 Except as provided in Section 8.3.1.1 and 8.3.1.2, within 90 Days prior to the beginning of each Contract Year, Seller shall declare the Total Facility Capacity for such Contract Year. Such declaration shall be based on the demonstrated generating capability of the Facility as determined in accordance with Appendix E.

8.2.2 After Seller's declaration under Section 8.2.1, Buyer shall have the right to require a test to re-demonstrate the capability of the Facility as follows:

8.2.2.1 After Seller's declaration of the Total Facility Capacity for the first Contract Year, Buyer may by notice to Seller ("Test Notice") require Seller to conduct a test to re-demonstrate the capability of the Facility. Buyer shall provide any such Test Notice no later than 30 Days after the Service Commencement Date ("Initial Testing Deadline"). If Buyer timely provides the Test Notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

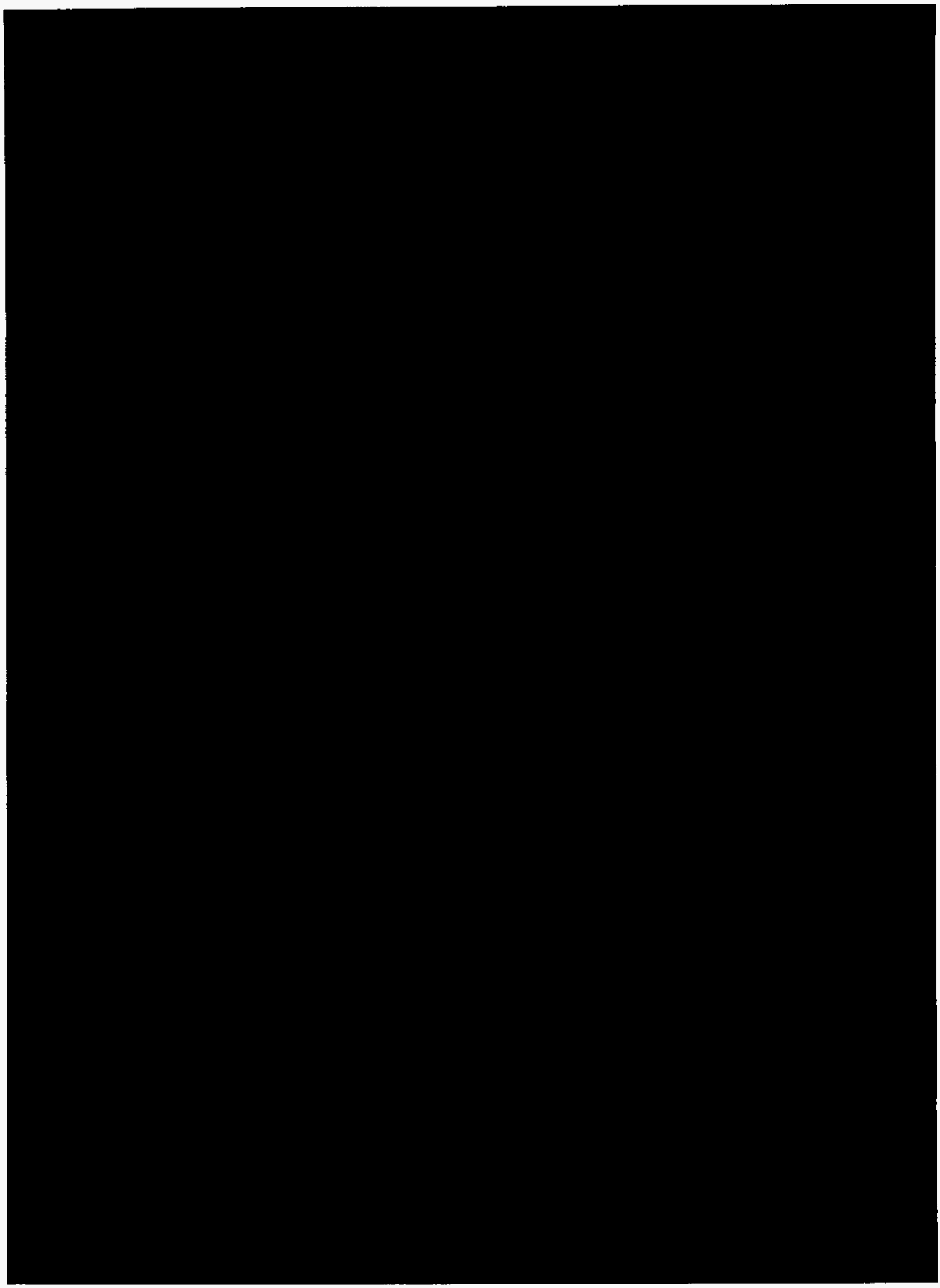
8.2.2.2 After the Initial Testing Deadline, if at any time Buyer has reasonable grounds for disputing Seller's declared amount of Total Facility Capacity (e.g., the delivery of energy by Seller in amounts less than Scheduled Energy), Buyer may provide to Seller a Test Notice to require Seller to conduct a test to re-demonstrate the capability of the Facility. Upon receipt of such notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

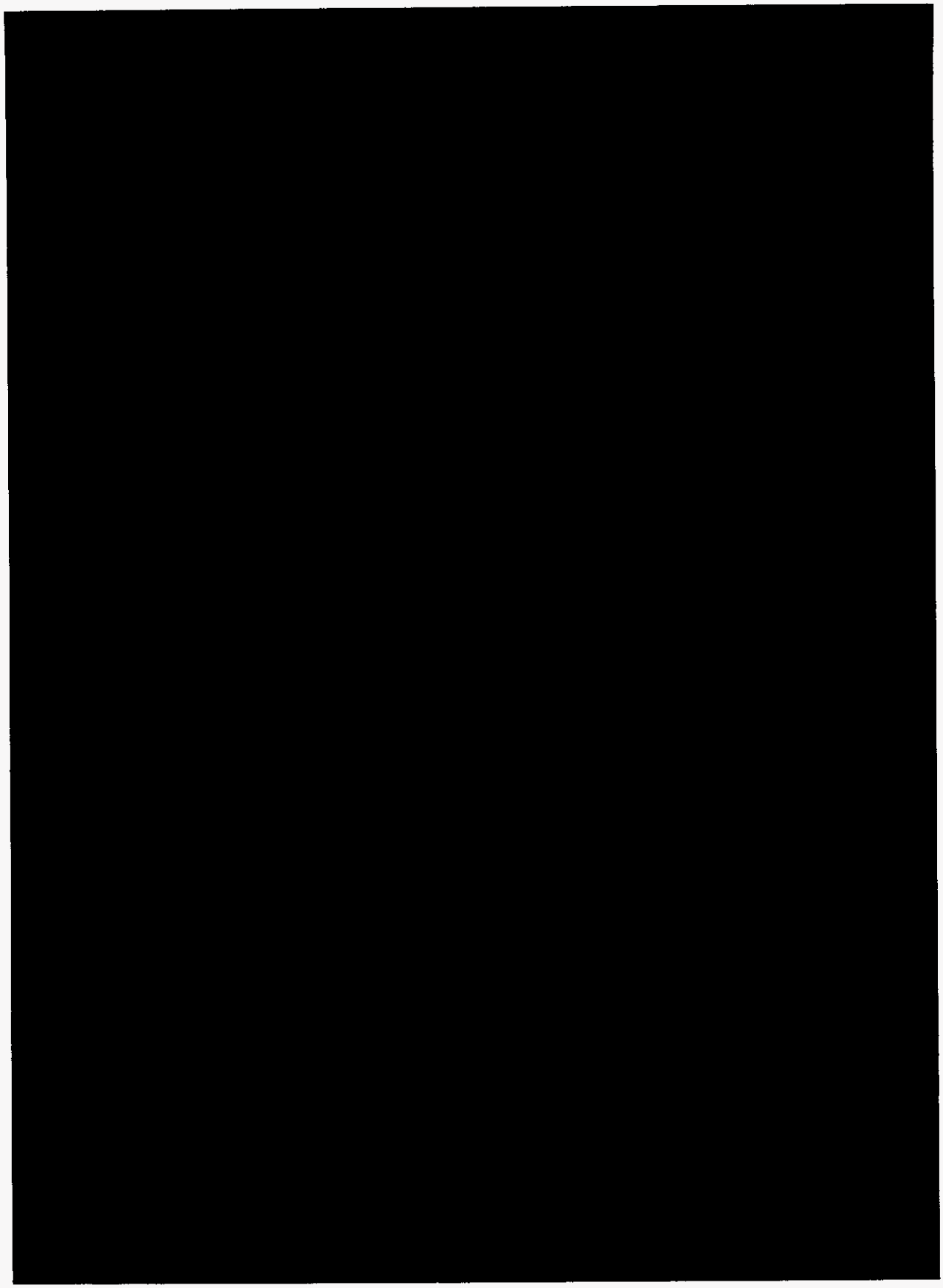
8.2.3 In the event that a test required by Buyer pursuant to Section 8.2.2 indicates that the generating capability of the Facility is different than the Total Facility Capacity declared pursuant to Section 8.2.1, Seller may (at its sole option) conduct additional test(s) of the Facility in accordance with Appendix E, such test(s) to be completed no later than 30 Days after the test conducted pursuant to Section 8.2.2. If Seller does not elect to conduct such additional test(s), the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated by the test conducted pursuant to Section 8.2.2. If Seller does elect to conduct additional testing, Seller shall provide Buyer prior notice of the Day(s) of such test(s) and the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated through such additional test(s). If such test(s) is performed coincident with Buyer's Schedule for any Day(s), Buyer shall pay Seller the costs of testing (including Gas and operation and maintenance costs) that are the responsibility of Buyer through the application of the Monthly Energy Payment for all Delivered Energy provided to Buyer. To the extent such test(s) is performed during a time

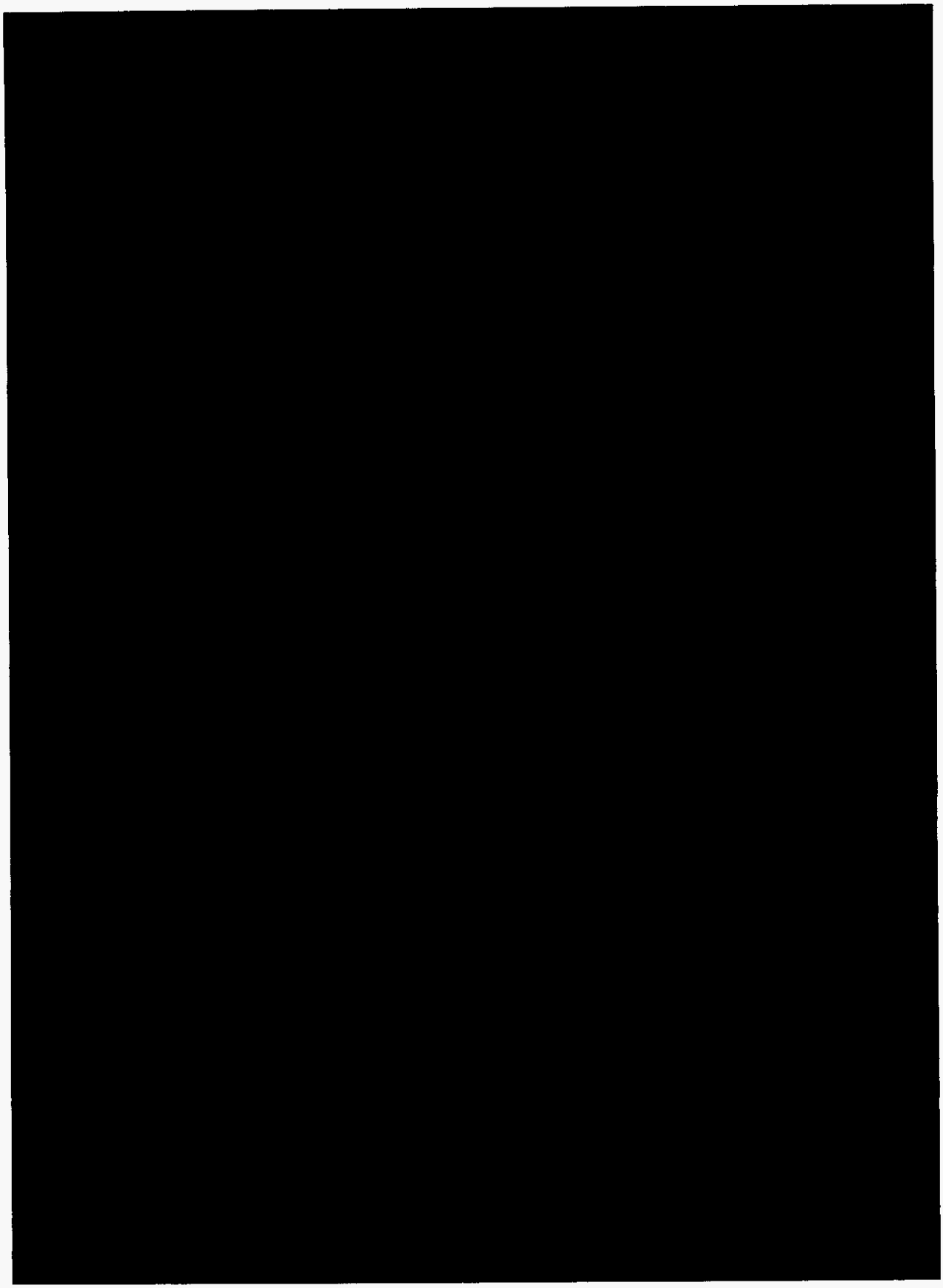
period in which energy will not be delivered to Buyer pursuant to a Schedule, Seller shall be responsible for all costs of testing (including Gas and operation and maintenance costs) and shall be entitled to utilize all energy produced during testing for its own purposes.

8.2.4 If the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3 as a result of a Test Notice provided by Buyer on or before the Initial Testing Deadline, the Total Facility Capacity shall be adjusted retroactively to the Service Commencement Date. In all other cases when the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3, the Total Facility Capacity shall be adjusted retroactively to the date of the applicable Test Notice. All capacity billing under Section 6.1 shall (if necessary and as soon as practicable) be retroactively adjusted as appropriate (with interest at the Interest Rate) to reflect such adjustment of the Total Facility Capacity.

8.3 [redacted]







ARTICLE 9

FUEL ARRANGEMENTS

9.1 Seller's Commitment. Subject to the provisions of this Agreement, Seller will use Commercially Reasonable Efforts to provide to the Facility the volume of Gas needed to provide Scheduled Energy.

9.2 Gas Transportation Arrangement and Charges.

9.2.1 Subject to the provisions of this Agreement, Seller will utilize up to [redacted] MMBtu per day of firm transportation capacity on the pipeline system of SNG from SNG's Zone 0 to Zone 2 under SNG's Contract Number FSNG284 constructed under South System 1, Phase 1 expansion that was placed in service on June 15, 2002 for deliveries to Point Code 807000, Plant Franklin, as amended ("SNG Contract") as necessary to provide Scheduled Energy under this Agreement. To the extent energy is supplied to Buyer from the Facility, Seller shall afford Buyer's Schedule priority with regard to the use of such transportation capacity that is available; provided, however, if a portion of the total amount of transportation capacity procured by Seller to the Plant is unavailable for any hour(s), Seller shall be permitted to reduce on a pro rata basis the amount of transportation capacity that it will utilize in order to satisfy Buyer's Schedule.

9.2.2 Buyer shall pay to Seller a Monthly Fuel Transportation Payment which shall be an amount equal to the product resulting from multiplying [redacted] MMBtu by the sum of: [redacted]

9.2.3 Buyer acknowledges that charges under the SNG Contract are currently discounted below SNG's maximum tariff rates and that such rates are subject to periodic increases as provided in the SNG Contract and to increases pursuant to actions by FERC. Buyer agrees to pay the then current rates each Month under the SNG Contract during the term of this Agreement.

9.2.4 Buyer acknowledges that Seller may have the right pursuant to Exhibit E of the SNG Contract to terminate that contract; however, Seller shall exercise that right with respect to the transportation capacity necessary to provide Scheduled Energy under this Agreement only if Buyer and Seller agree on mutually acceptable replacement transportation arrangements.

9.2.5 Buyer acknowledges that SNG may impose imbalance, cash-out and other types of charges, including penalty charges, pursuant to its FERC approved tariff under certain conditions ("Penalty Charges"). Buyer agrees to be responsible for and pay or reimburse Seller for any Penalty Charges billed to Seller by SNG that result from any action or failure to act of Buyer under this Agreement. The Parties agree to cooperate in order to attempt to minimize Penalty Charges.

9.2.6 [redacted]

[redacted]

9.2.7 In the event that accommodating Buyer's Schedule would require Gas transportation capacity in addition to that set forth in Section 9.2.1, Seller shall make Commercially Reasonable Efforts to obtain (if available) additional capacity at Buyer's expense and Buyer shall reimburse Seller based on SNG's interruptible transportation rate from Zone 0 to Zone 2 in effect at the time. To the extent Seller is unable to obtain such additional capacity at or below such interruptible transportation rate and such capacity is available, Seller shall make Commercially Reasonable Efforts to provide Buyer the option of having Seller purchase such additional capacity at the higher rate. If Buyer desires to have Seller purchase such additional capacity at the higher rate, Seller shall make Commercially Reasonable Efforts to obtain such capacity to accommodate Buyer's Schedule and Buyer shall reimburse Seller for all associated costs. To the extent that Buyer does not desire to have Seller purchase such additional capacity at the higher rate or Seller is unable to obtain such capacity, Seller shall have a Delivery Excuse to that extent.

9.3 Interruption of Gas Supplies

9.3.1 In the event that Gas supplies are interrupted due to any circumstance affecting Seller's Gas suppliers that qualifies as an event of force majeure as defined in the North American Energy Standards Board's Base Contract for Sale and Purchase of Natural Gas:

A. Seller shall use Commercially Reasonable Efforts to arrange for alternate Gas supplies to overcome such an interruption. If alternate Gas supplies are available, Seller shall offer to Buyer, and Buyer shall have the option to immediately accept, such alternate Gas supplies at the price quoted by Seller.

B. If Seller is unable to arrange for alternate Gas supplies or if Buyer does not accept such alternate Gas supplies pursuant to subparagraph A above, Buyer may arrange to sell alternate gas supplies to Seller at the Gas Price (as defined in Appendix B) by delivering such Gas to SNG at a point on its pipeline at which Seller can schedule receipts of such Gas under the SNG Contract. Buyer shall cooperate with Seller and SNG in order to ensure that such supplies are nominated, scheduled and delivered to SNG for transportation under the SNG Contract and under the terms of SNG's FERC approved tariff. Buyer shall be responsible for any Penalty Charges resulting from any difference between the volume scheduled for delivery by Buyer to and receipt by SNG and the actual volume delivered by Buyer to and received by SNG.

9.3.2 In the event that there is no arrangement for alternate Gas supplies under Section 9.3.1, the interruption of Gas supplies described in Section 9.3.1 shall constitute a Delivery Excuse as defined in this Agreement.

9.3.3 Notwithstanding any other provision of this Agreement, Seller shall not be obligated to obtain or use any Gas storage services in order to provide Gas under this Agreement.

9.4 Scheduling Changes. In the event that Buyer requests a Schedule change pursuant to Section 5.1.2 after the Scheduling Deadline, Seller shall quote a price for supplying incremental Gas needed to accommodate an increase in Scheduled Energy (subject to Gas availability and the ability to schedule delivery of Gas) or for selling excess Gas resulting from a decrease in Scheduled Energy, as appropriate. Upon receipt of Seller's quote, Buyer shall immediately exercise one of the following options: (i) not changing the existing Schedule: (ii) proceeding with the requested Scheduling Change and the increase or decrease in Gas supplies based on the quoted price (to buy the incremental Gas supply, or to sell the excess Gas supply, as applicable), or (iii) proceeding with the increase (if applicable) in Scheduled Energy and notifying Seller that Buyer will supply the required incremental Gas supply utilizing the procedures set forth in Section 9.3.1B.

ARTICLE 10

ELECTRIC METERING

10.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

10.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

10.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

10.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 11

BILLING AND PAYMENT

11.1 Timing and Method of Payment. Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable [redacted]

[redacted]("Payment Due Date"). If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

11.2 **Late Payment.** Amounts that are owed Seller shall, if not remitted within the time period specified under Section 11.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 21.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

11.3 **Disputed Billings.** In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. Notwithstanding such dispute, [redacted]

11.4 **Adjustments.** If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the

overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than [redacted] Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] Days

after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party

shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of

times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller

written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within 30 Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 18.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

13.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than 30 Days thereafter, Seller may initiate a Change in Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

13.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the

Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 14

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

14.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) except for any Taxes included in the Gas Charges, Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

14.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and

against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

14.3 Limitation of Liability.

14.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

14.3.2 SUBJECT TO SECTION 16.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY

DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

14.3.3 In the event that any provision of this Section 14.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 14.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 14.2 or limit the remedies set forth in this Agreement for an Event of Default.

14.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 15

FORCE MAJEURE EVENT

15.1 Force Majeure Event Defined.

15.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

15.1.2 Notwithstanding anything contained in Section 15.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

15.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

15.2.1 The non-performing Party shall give the other Party written notice within 3 Business Days of the commencement of the Force Majeure Event, with available details to be supplied within 15 Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

15.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

15.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

15.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

15.3 Effect of Force Majeure Event.

15.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

15.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

15.4 [redacted]

ARTICLE 16

EVENT OF DEFAULT

16.1 Event of Default. The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

16.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within 15 Days after receiving written notice of such failure from the Party to which such payments are due;

16.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

16.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

16.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such

Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within 60 days of the filing thereof;

16.1.5 The failure of any Party to comply with the requirements of Article 20 regarding creditworthiness and/or security;

16.1.6 The failure of a Party to comply with the requirements of Article 19 regarding assignment;

16.1.7 Any representation or warranty made by a Party under Article 17 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within 30 Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

16.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

16.1.9 [redacted]

16.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for 30 Days

after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of 30 Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed 90 Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 16.1.10 shall not apply to: (i) any event described in Sections 16.1.1 through 16.1.9; (ii) any event described in Sections 5.9, 5.10, and 8.3 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 16.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party".

16.2 Exclusive Remedies.

16.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

16.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than 20 Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 21.3 and 21.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in

Sections 16.2.3 or 16.2.4 below. The exercise by a Party of its rights under this Section 16.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

16.2.3 With respect to an Event of Default by or attributable to Buyer, within 15 Days after Seller's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within 30 Days after such notice, the two independent parties shall select a third independent party to determine the Seller's Damages. Within 60 Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within 5 Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 18 and the arbitration order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration

finding or order. As used herein, "Seller's Damages" means [redacted]

16.2.4 With respect to an Event of Default by or attributable to Seller, within 15 Days after Buyer's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within 30 Days after such notice, the two independent parties shall select a third independent party to determine the Buyer's Damages. Within 60 Days after such notice, the 3 independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within 5 Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 18 and the arbitration order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration

finding or order. As used herein, "Buyer's Damages" [redacted]

ARTICLE 17

REPRESENTATIONS AND WARRANTIES

17.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

17.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

17.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or

other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

17.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a breach or default under any evidence of its indebtedness or any other agreement or instrument to which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

17.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

17.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 18

DISPUTE RESOLUTION

18.1 Senior Officers.

18.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and, unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

18.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

18.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

18.2 Arbitration.

18.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 18.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate

an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will be made by notice to the other Party and to the AAA within 10 Days or, in the case of payment disputes, 5 Days after the date of the giving of notice of the demand for arbitration. The arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within 10 Days or, in the case of payment disputes, 5 Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

18.2.2 Subject to Section 16.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption

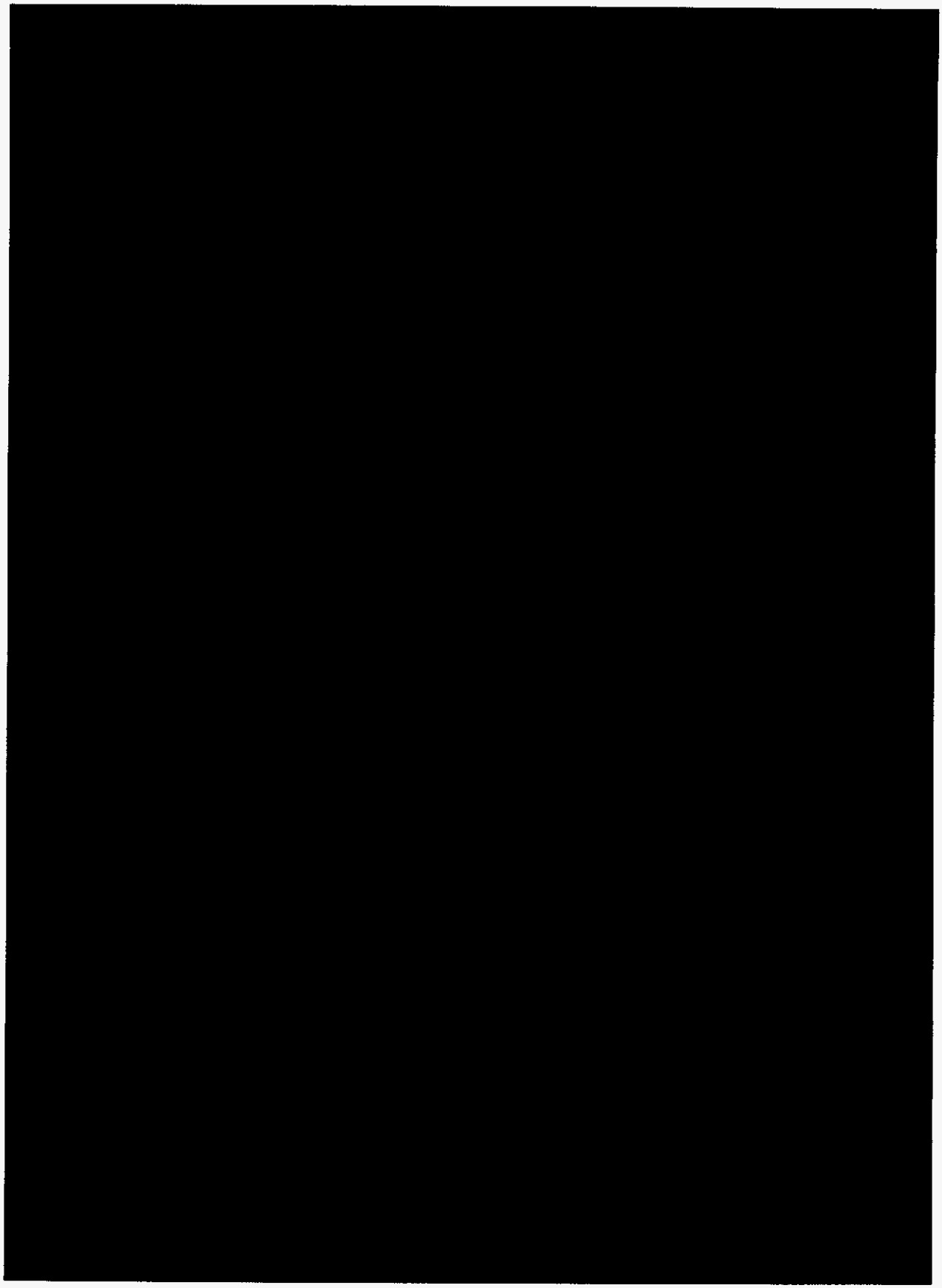
damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 21.2; provided further, notwithstanding any provision in Article 21, Confidential Information, to the extent relevant, may be disclosed by any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

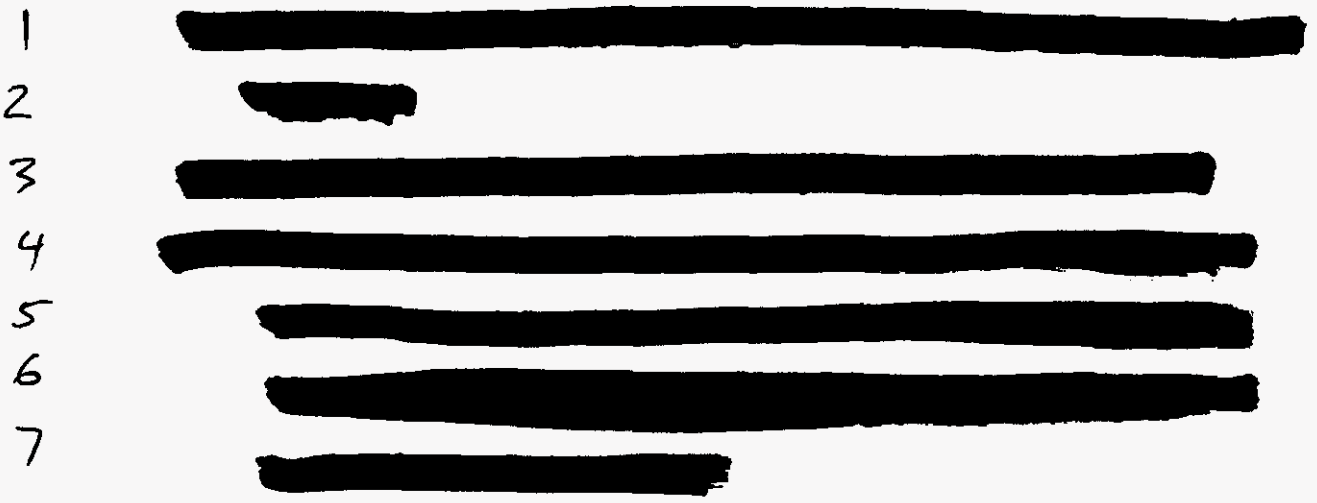
18.3 Binding Nature of Proceedings. Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 18.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 19

ASSIGNMENT

19.1 Assignment. Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with [redacted]





who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

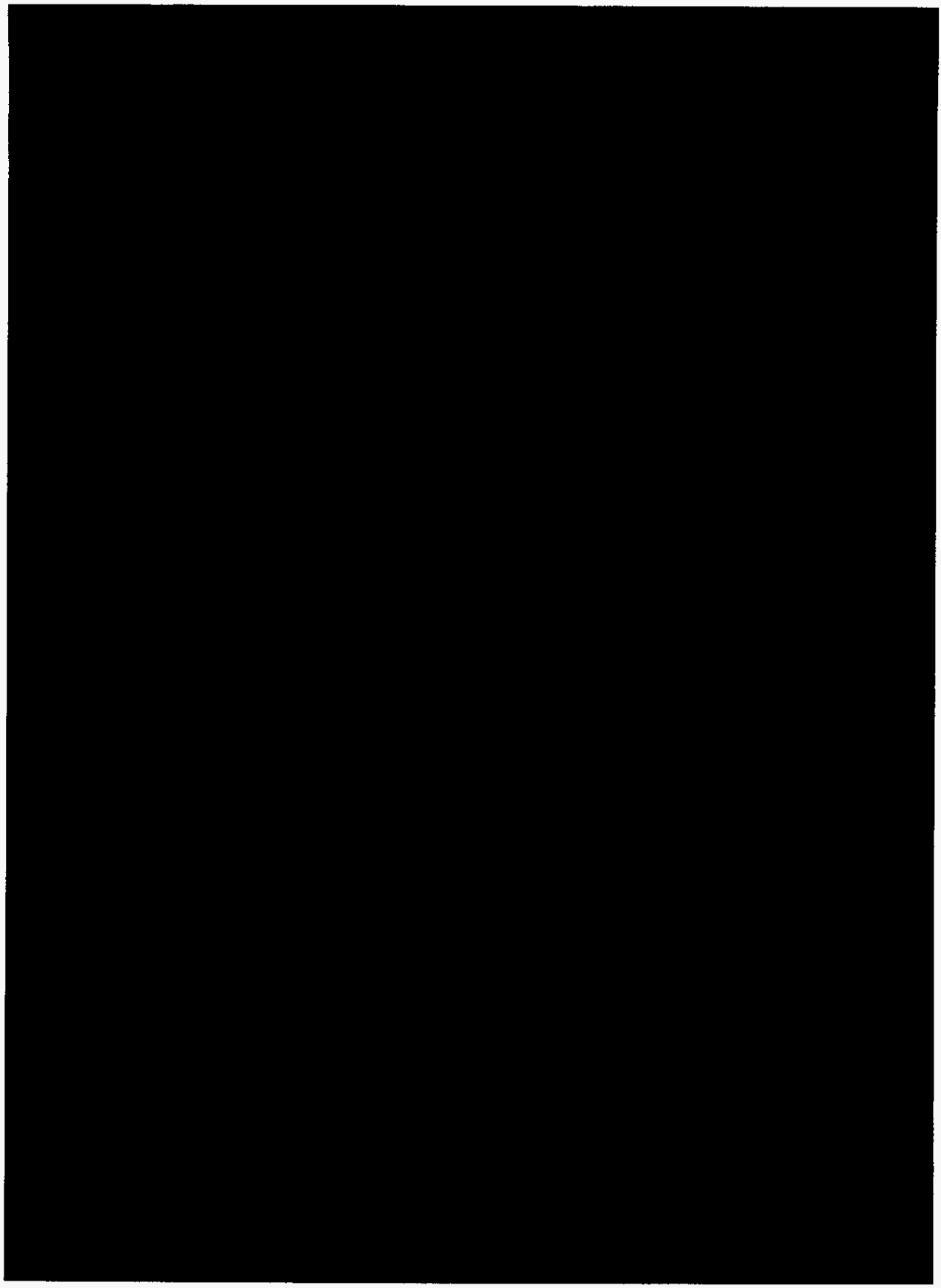
19.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions").

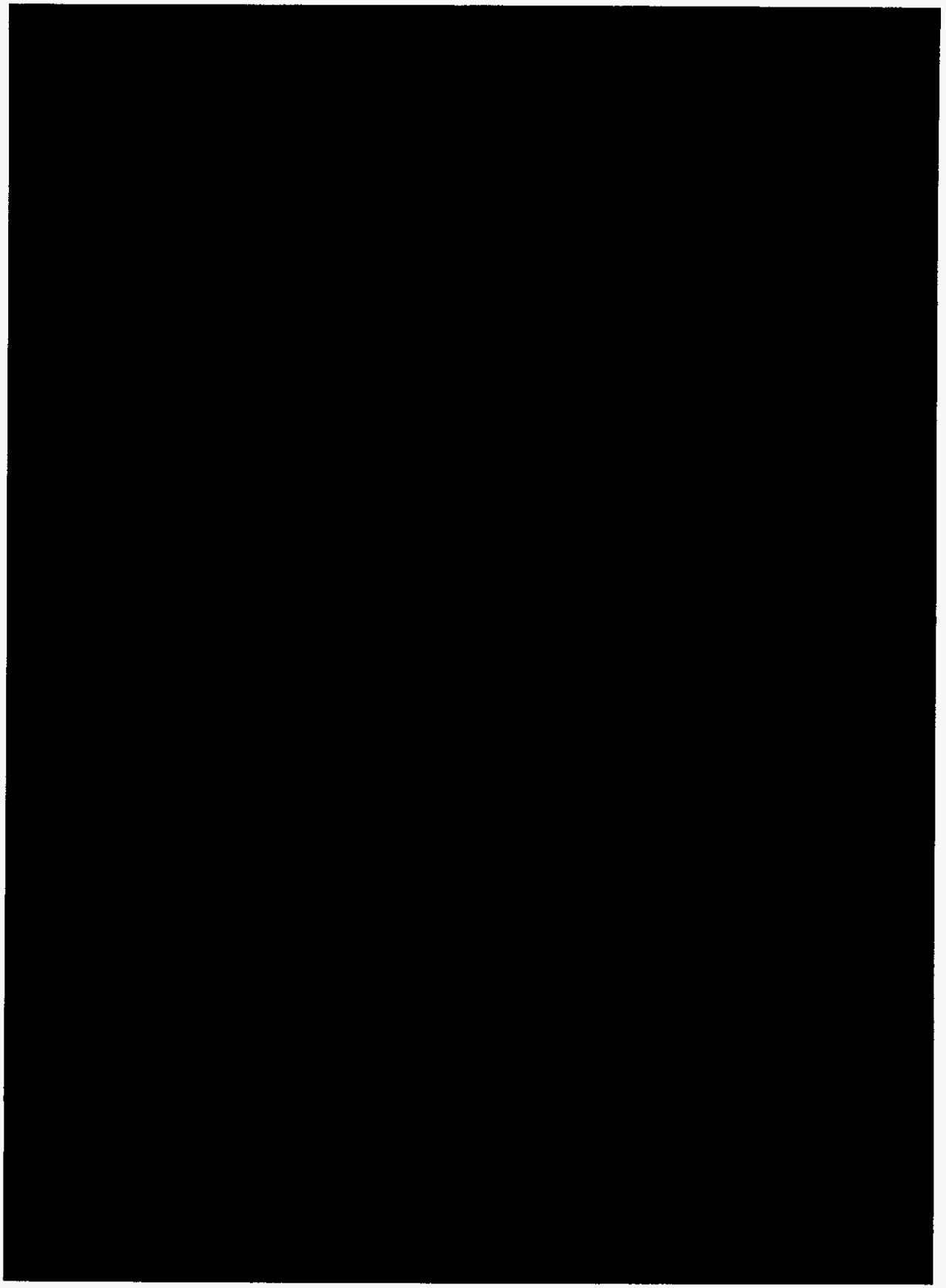
Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

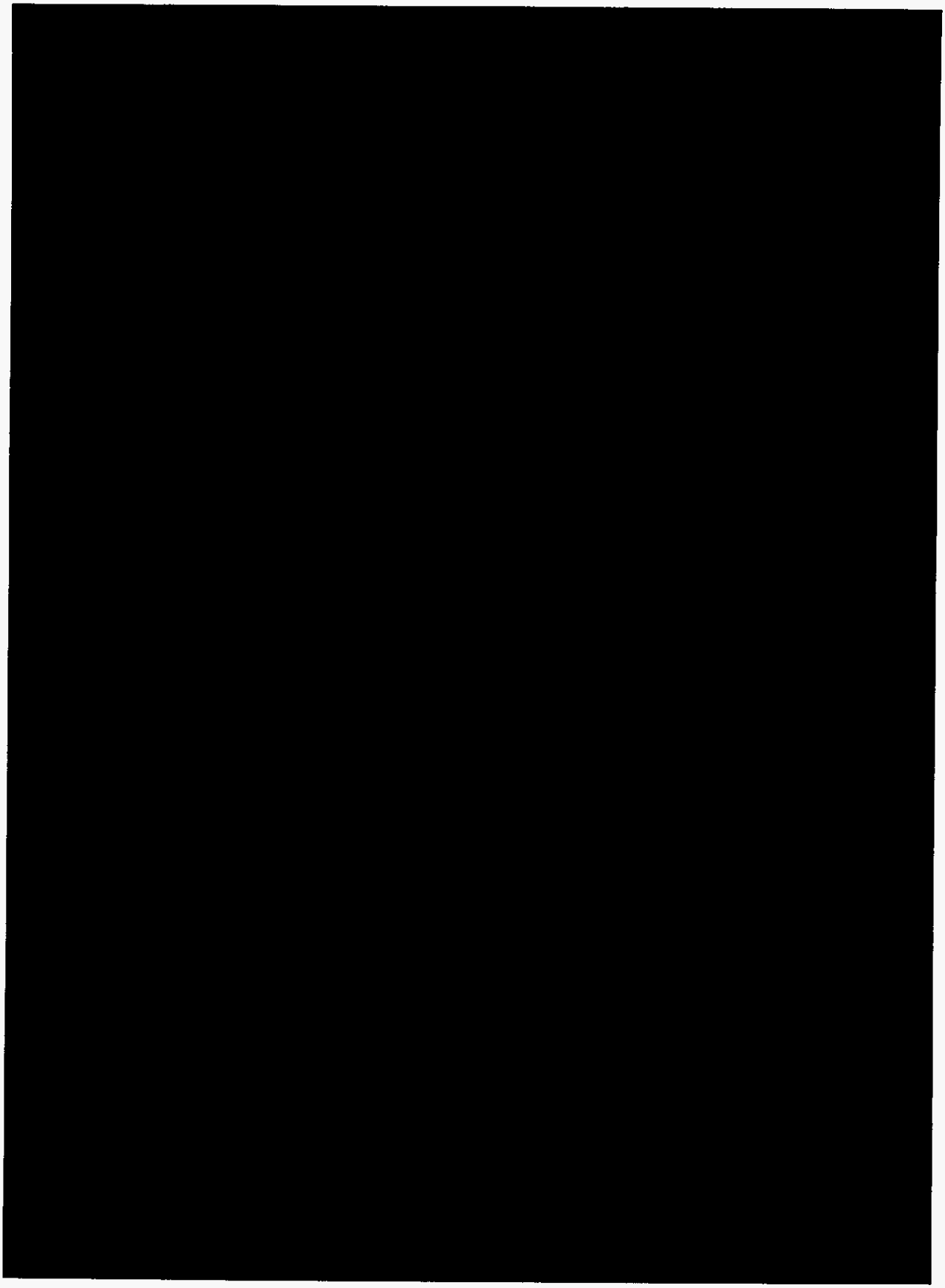
ARTICLE 20

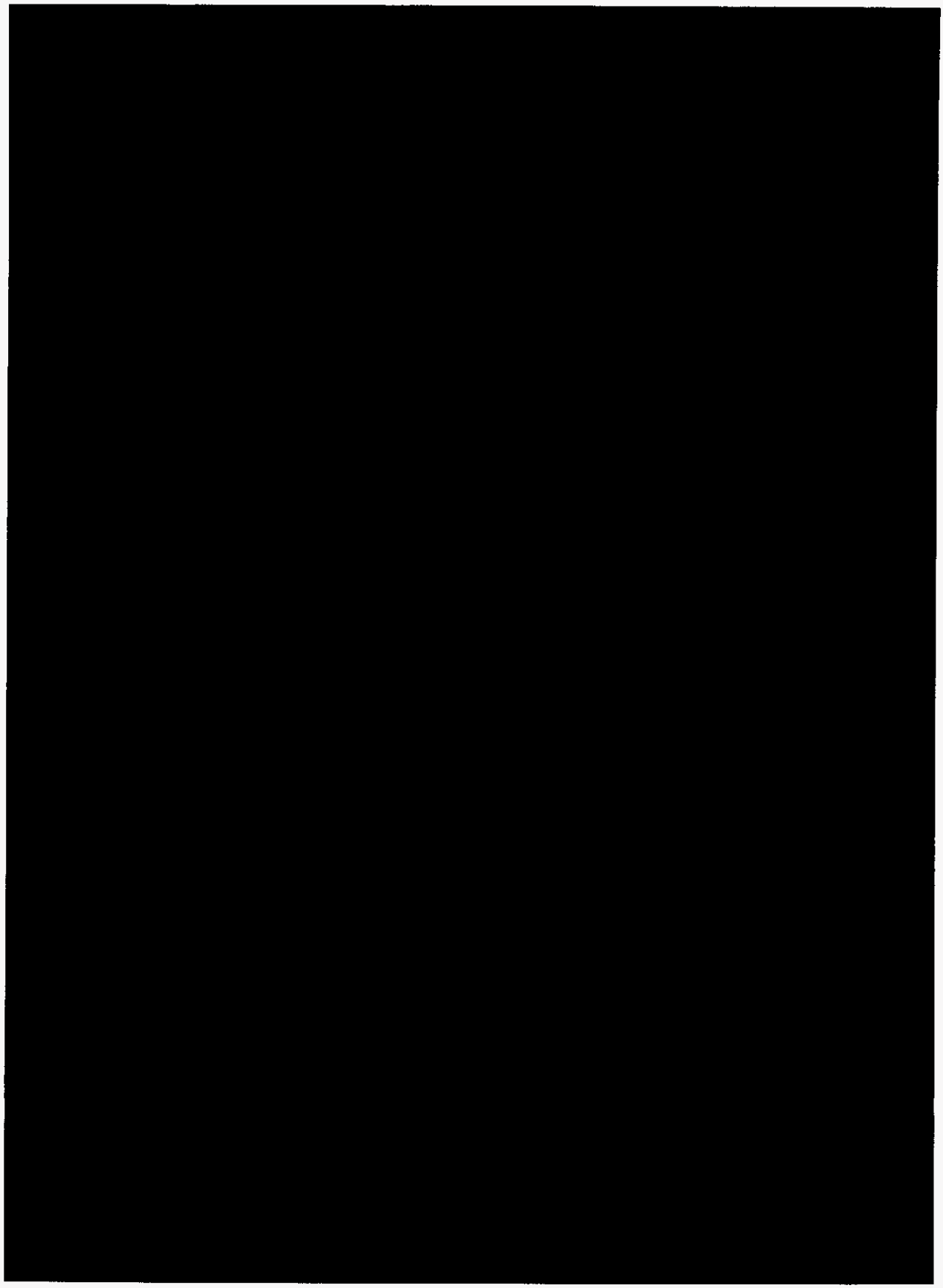
CREDITWORTHINESS AND SECURITY

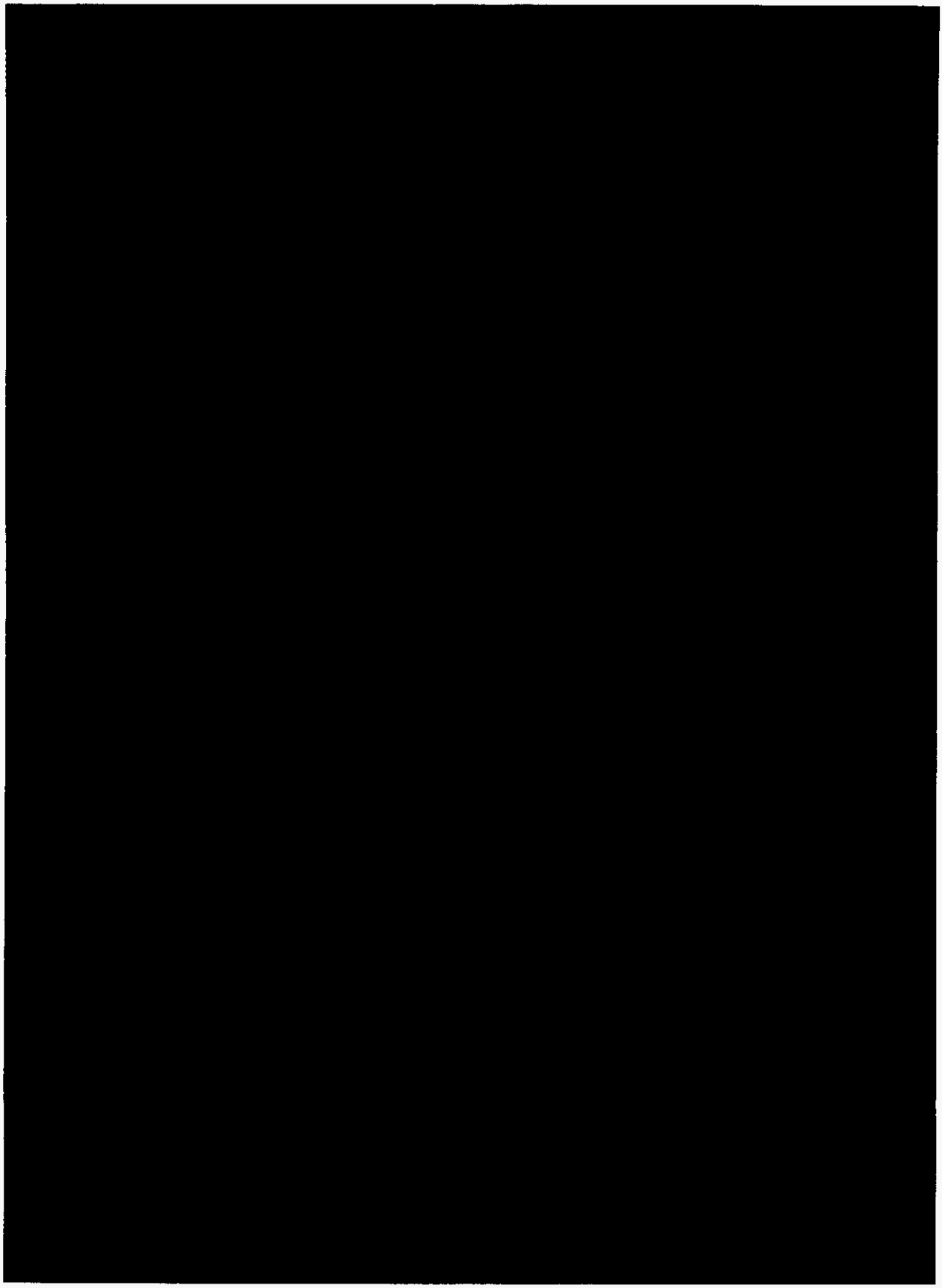
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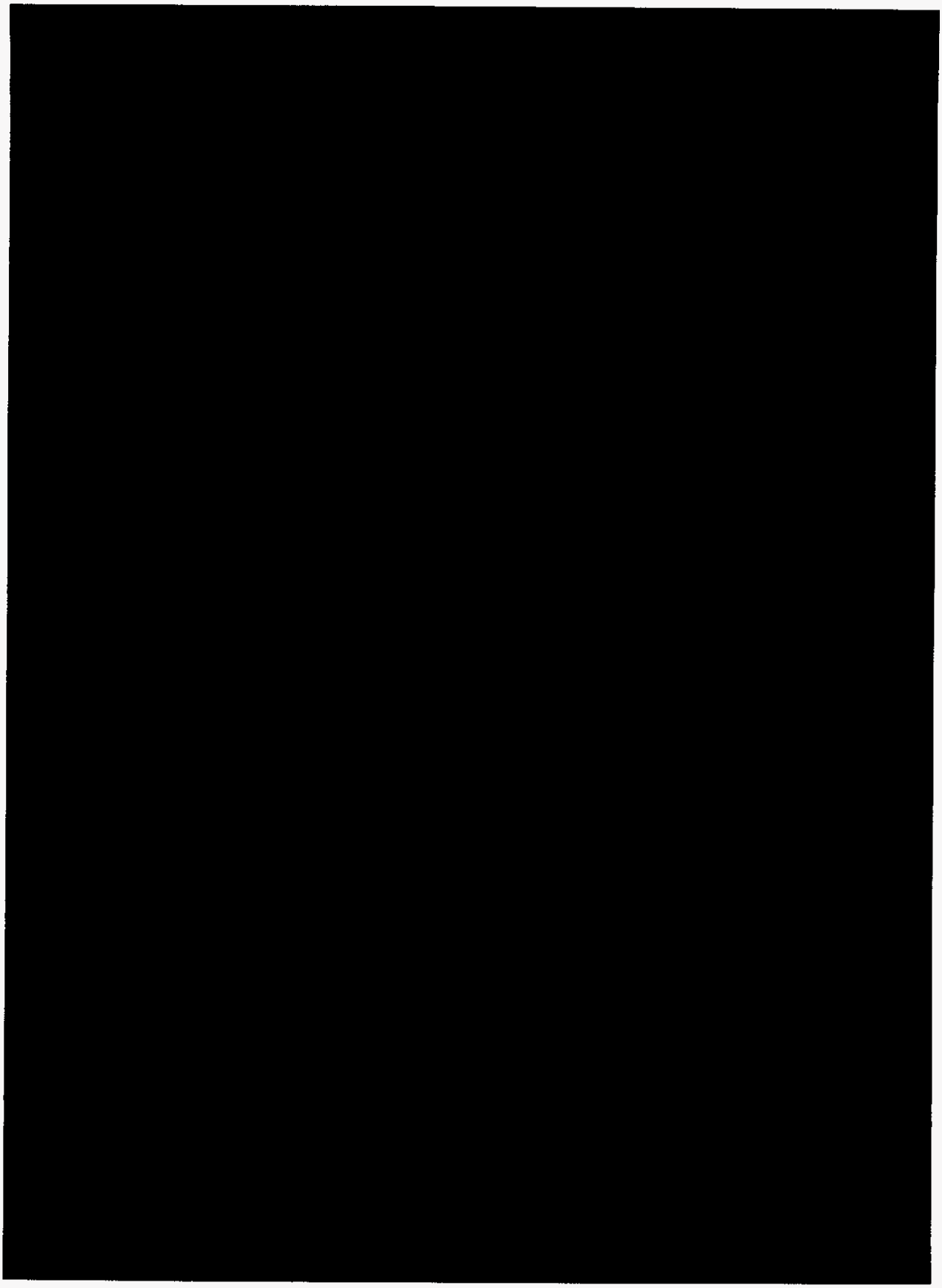


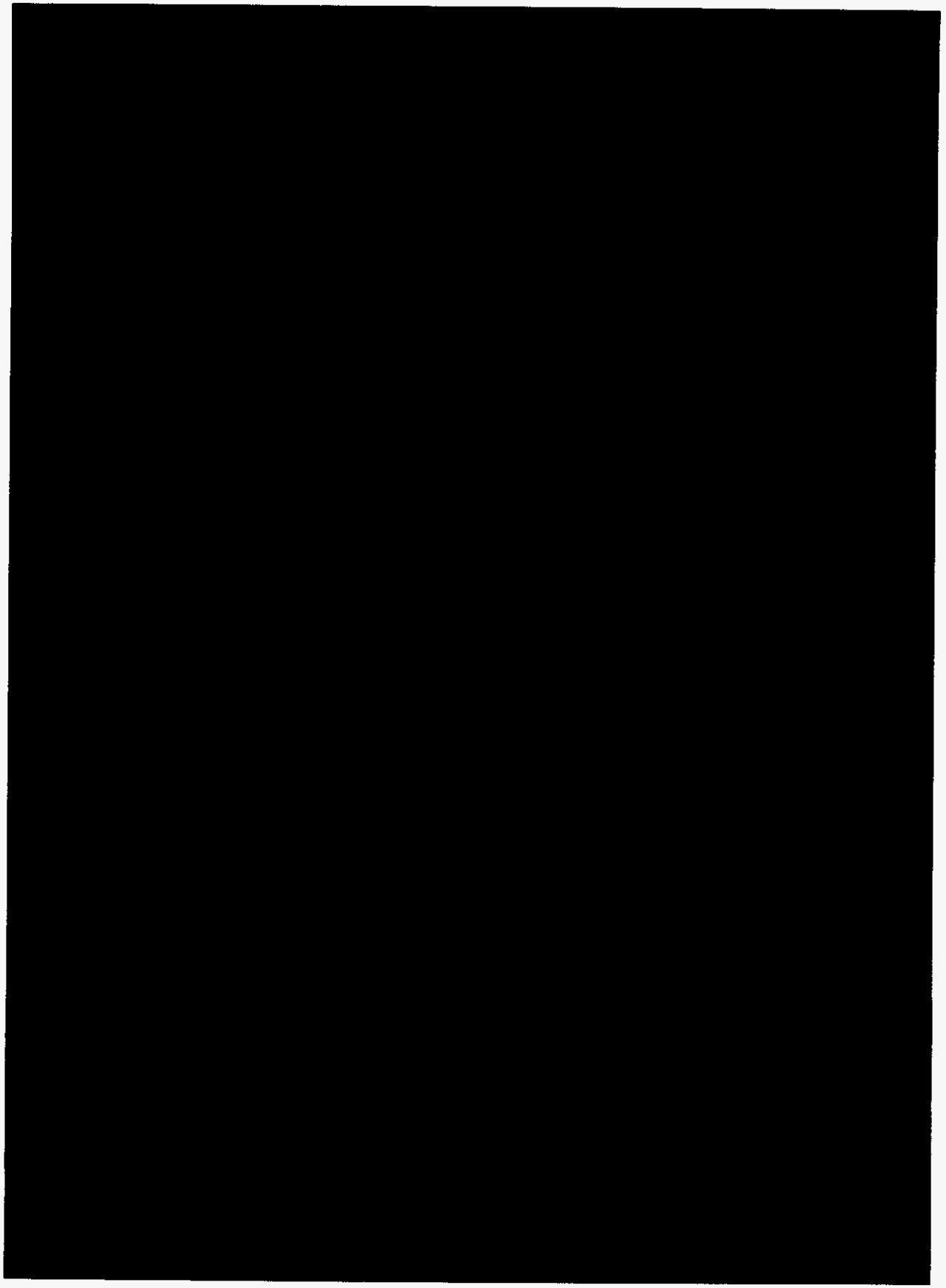












ARTICLE 21

MISCELLANEOUS

21.1 Governing Law; Waiver of Jury Trial.

THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE, REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

21.2 Confidentiality.

21.2.1 Scope of Protection.

(i) For purposes of this Section 21.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller

when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Southern Power or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Southern Power or any of its Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SERUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to maintain such confidentiality;

and (iii) Seller has notified Buyer of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the reasonable judgment of Buyer should have access to such Seller Confidential Information and are bound by an obligation to maintain such confidentiality provided that Buyer shall be responsible for any use or disclosure of such Seller Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Buyer from providing Seller Confidential Information to the NERC or SEARUC solely to the extent that (i) Buyer determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability, (ii) such entity is obligated to maintain such confidentiality, and (iii) Buyer has notified Seller of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iv) Notwithstanding the foregoing, either Party may disclose Confidential Information (i) to the extent relevant, to the independent parties determining Seller's Damages or Buyer's Damages (as appropriate), and (ii) to its and its Affiliates' employees, officers, directors, accountants, counsel and other advisors who need to know such information in connection with the performance of their duties or services for the disclosing Party or its Affiliates; provided, however, that such Persons shall be required to maintain the confidentiality of such information consistent with the requirements of this Agreement.

21.2.2 Required and Other Disclosure.

(i) Notwithstanding anything in this Section to the contrary, if Buyer is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Seller Confidential Information or otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent

with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure

request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 21.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was

previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 21.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 21.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to

disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the

Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

The obligations under this Section 21.2 with respect to any Party shall survive until the earlier of [redacted]

21.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 14.2 and 14.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

21.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for

the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

21.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

21.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

21.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

21.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual

understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

21.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

21.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

21.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

21.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

21.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

21.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President, General Counsel and Assistant Secretary
Southern Power Company
600 North 18th Street
Birmingham, Alabama 35203

Telephone: 205-257-0472
Facsimile: 205-257-2027

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305 552-2905

Either Party may change the information set forth in this Section 21.14 by giving written notice to the other Party in the manner prescribed by this Section.

21.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

21.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

21.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the

schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

21.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or

provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

21.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer 60 Days written notice in which event Southern Company Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

21.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

21.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix H. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Southern Power Company

BY: _____

NAME: William N. McKenzie

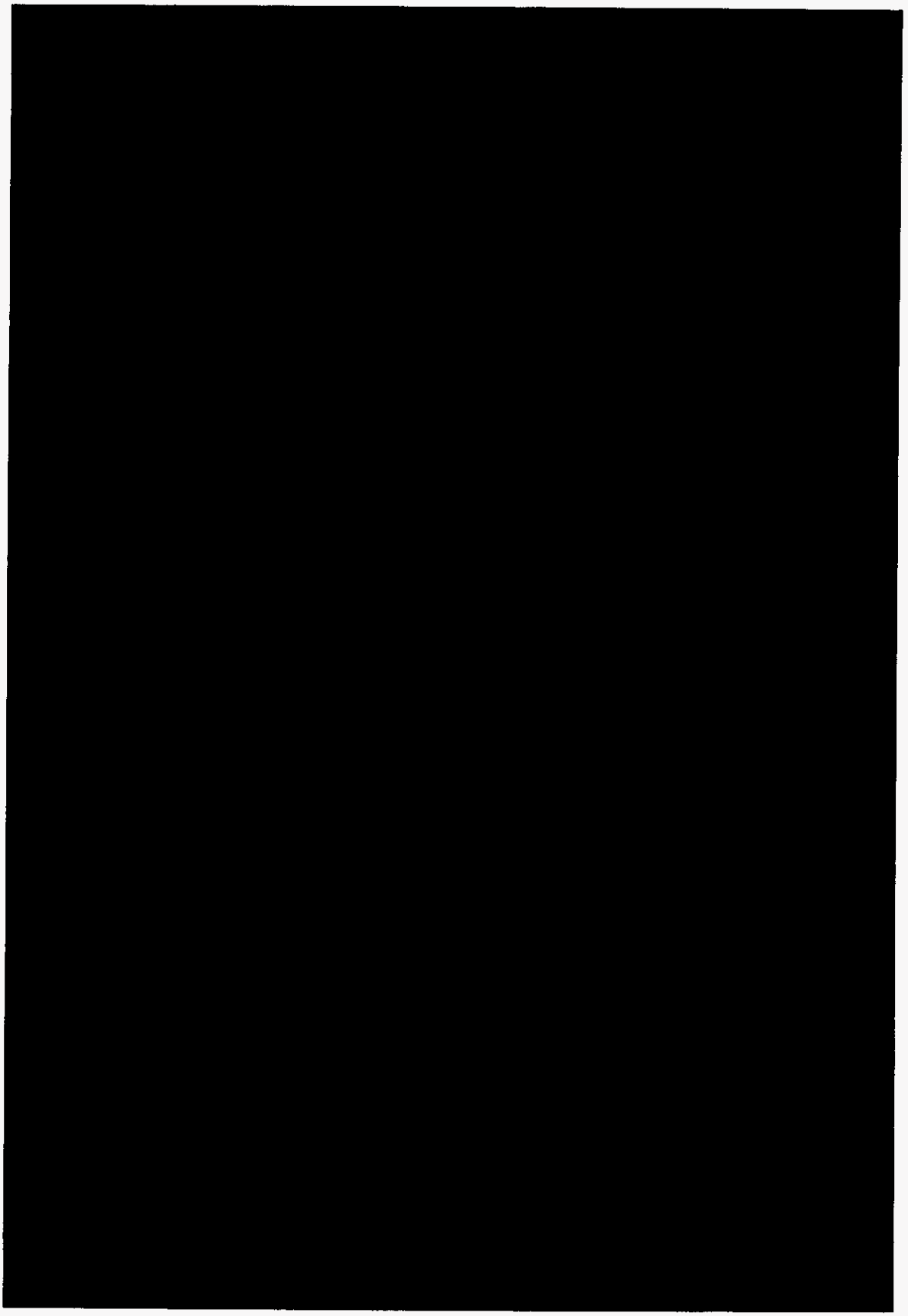
TITLE: Vice President

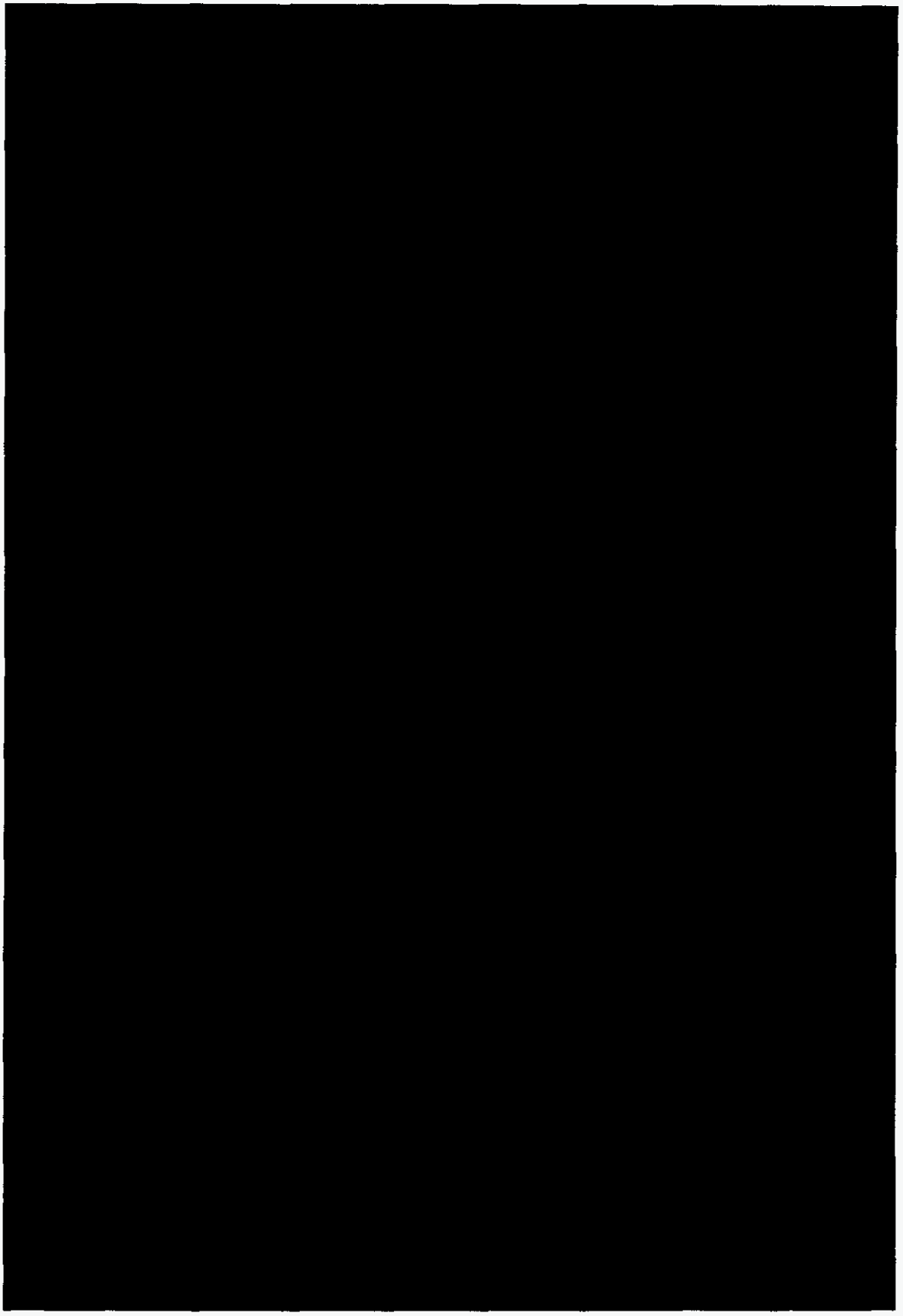
FLORIDA POWER & LIGHT COMPANY

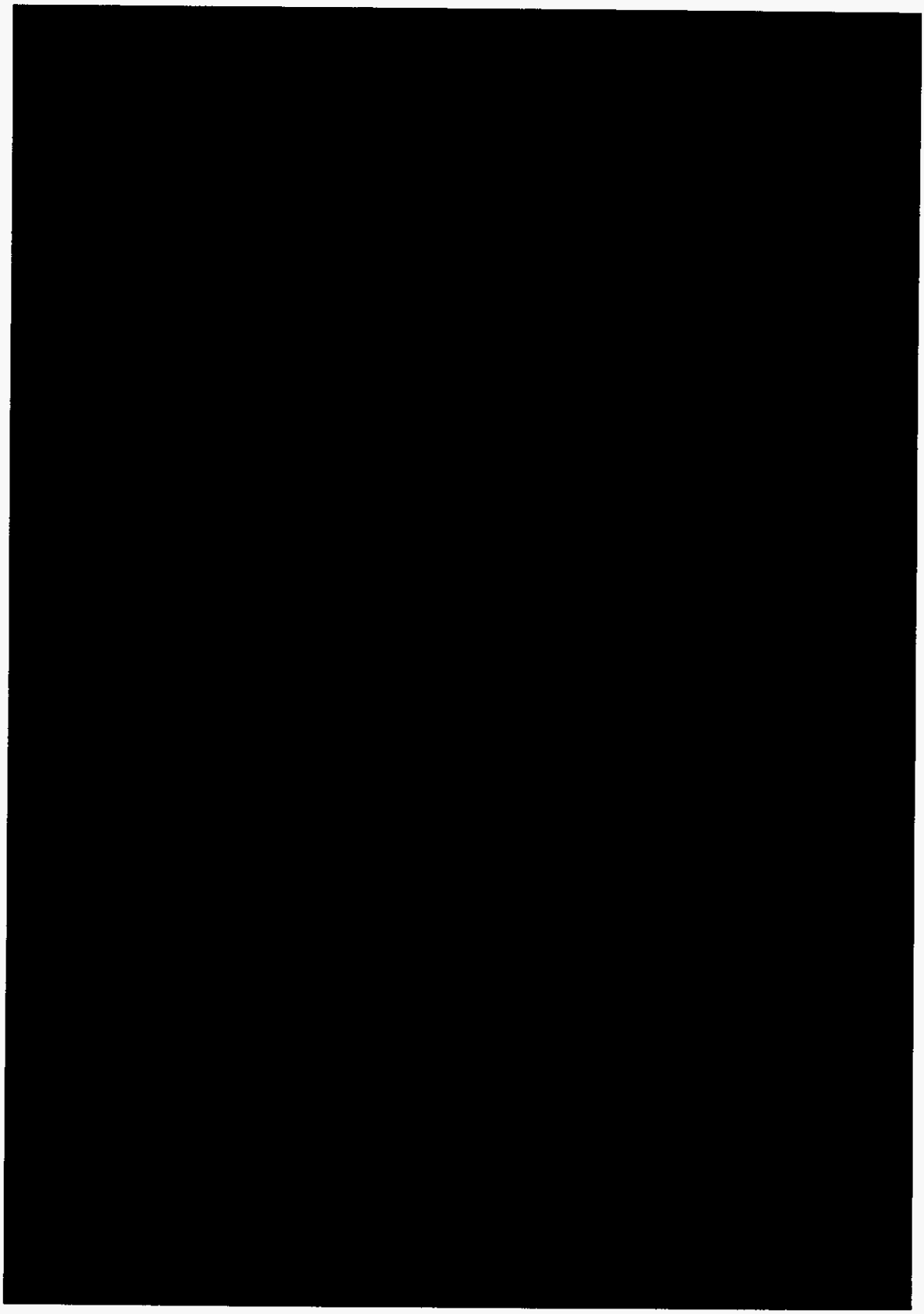
BY: _____

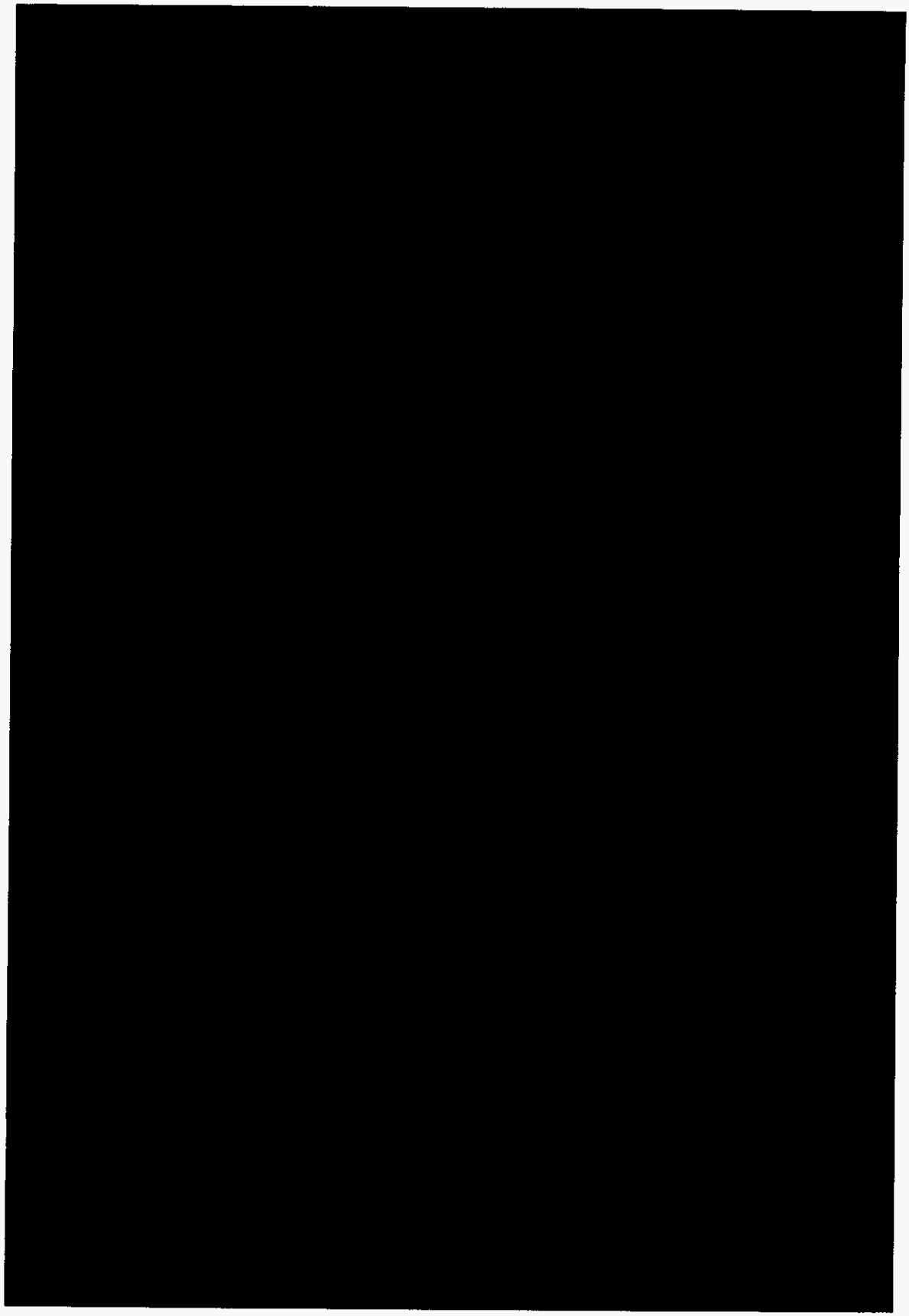
NAME: Terry L. Morrison

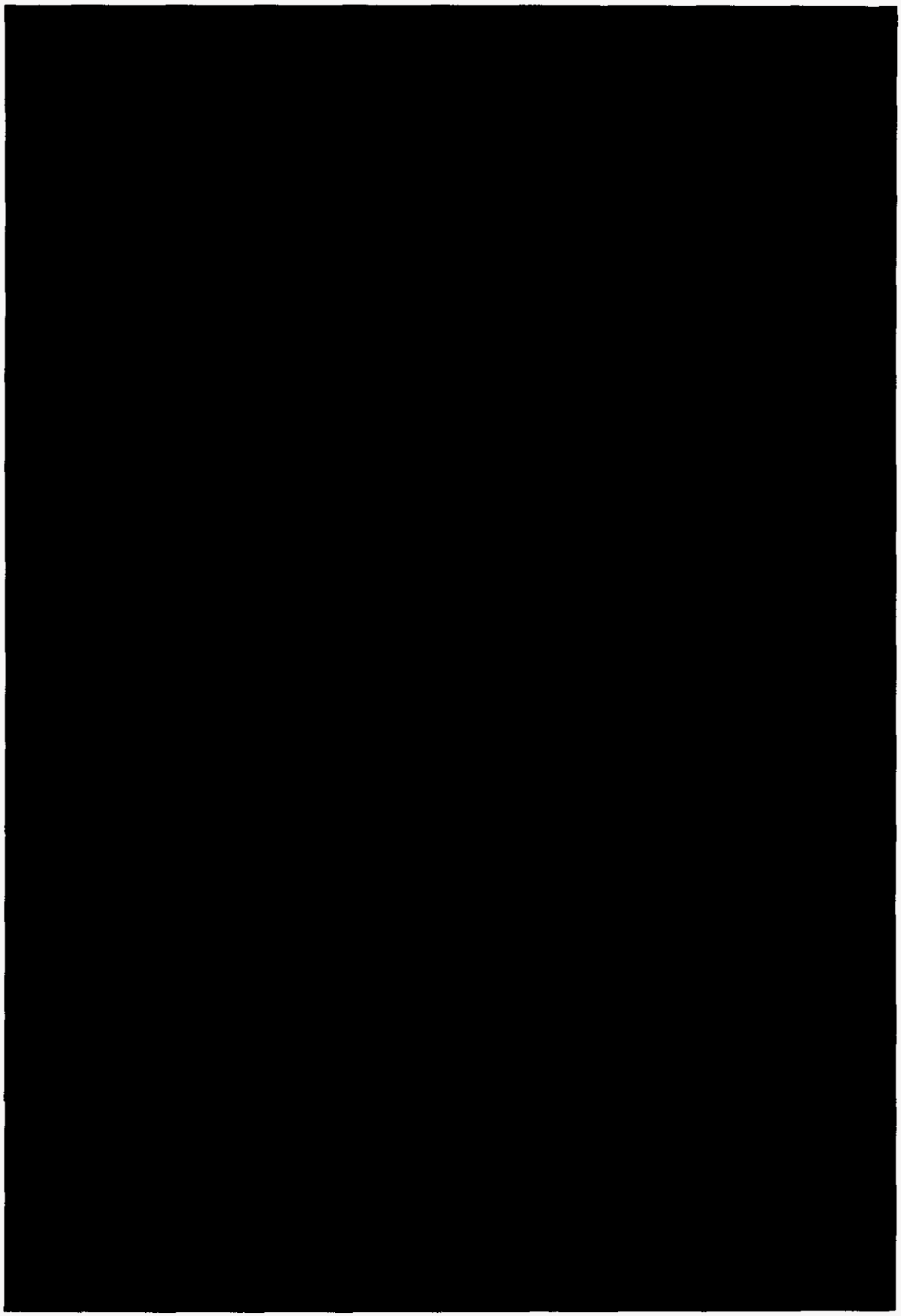
TITLE: Vice President

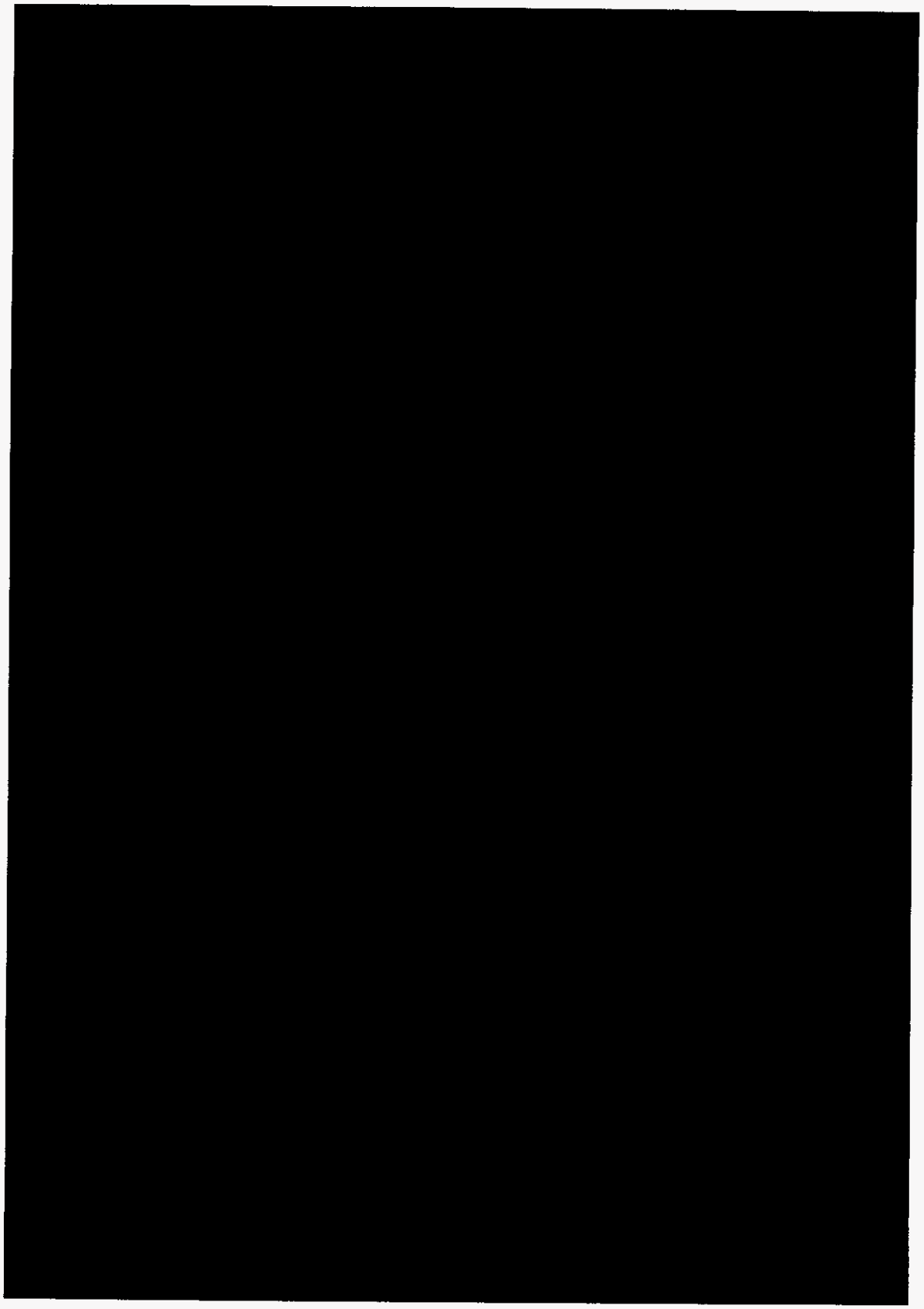


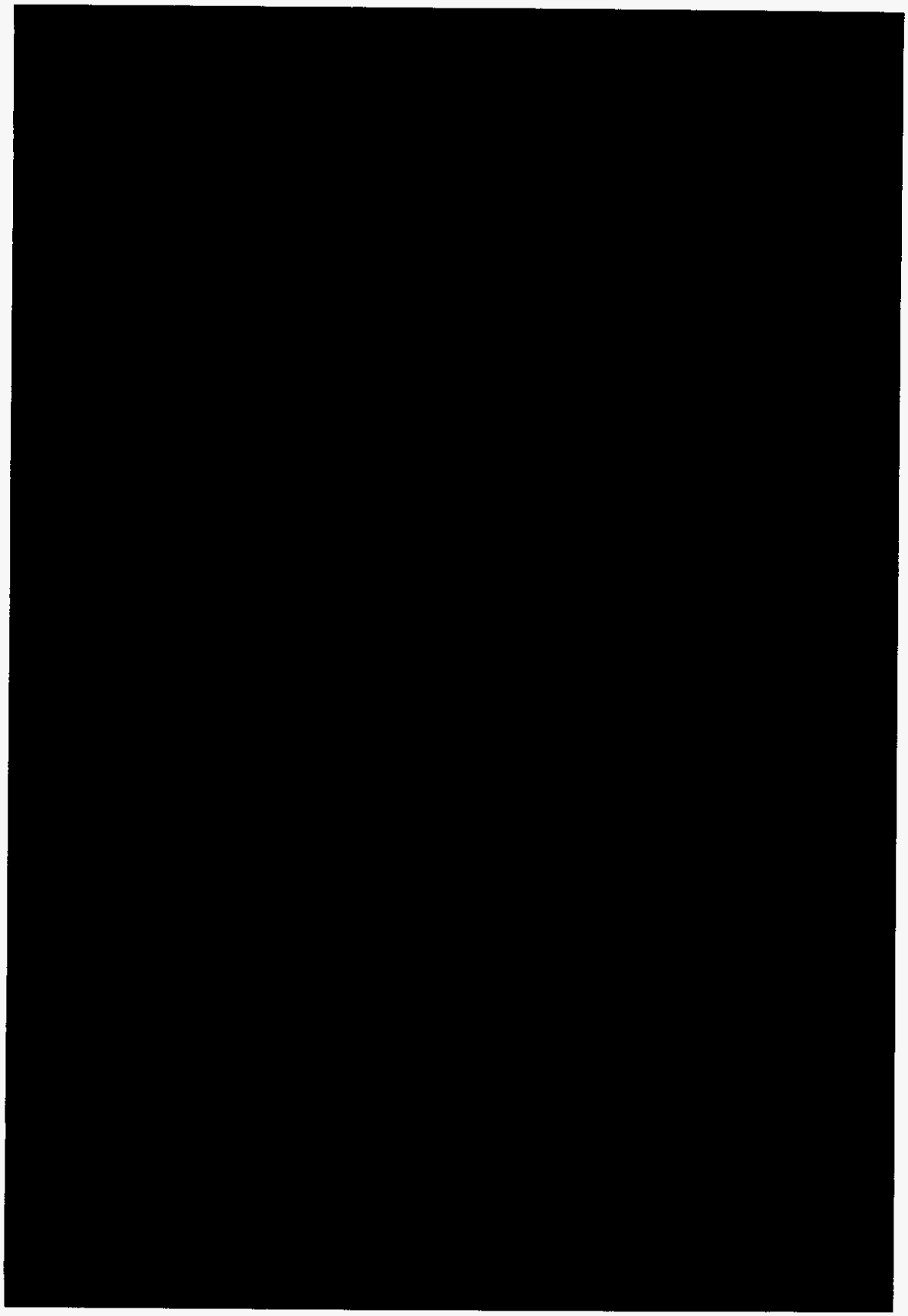


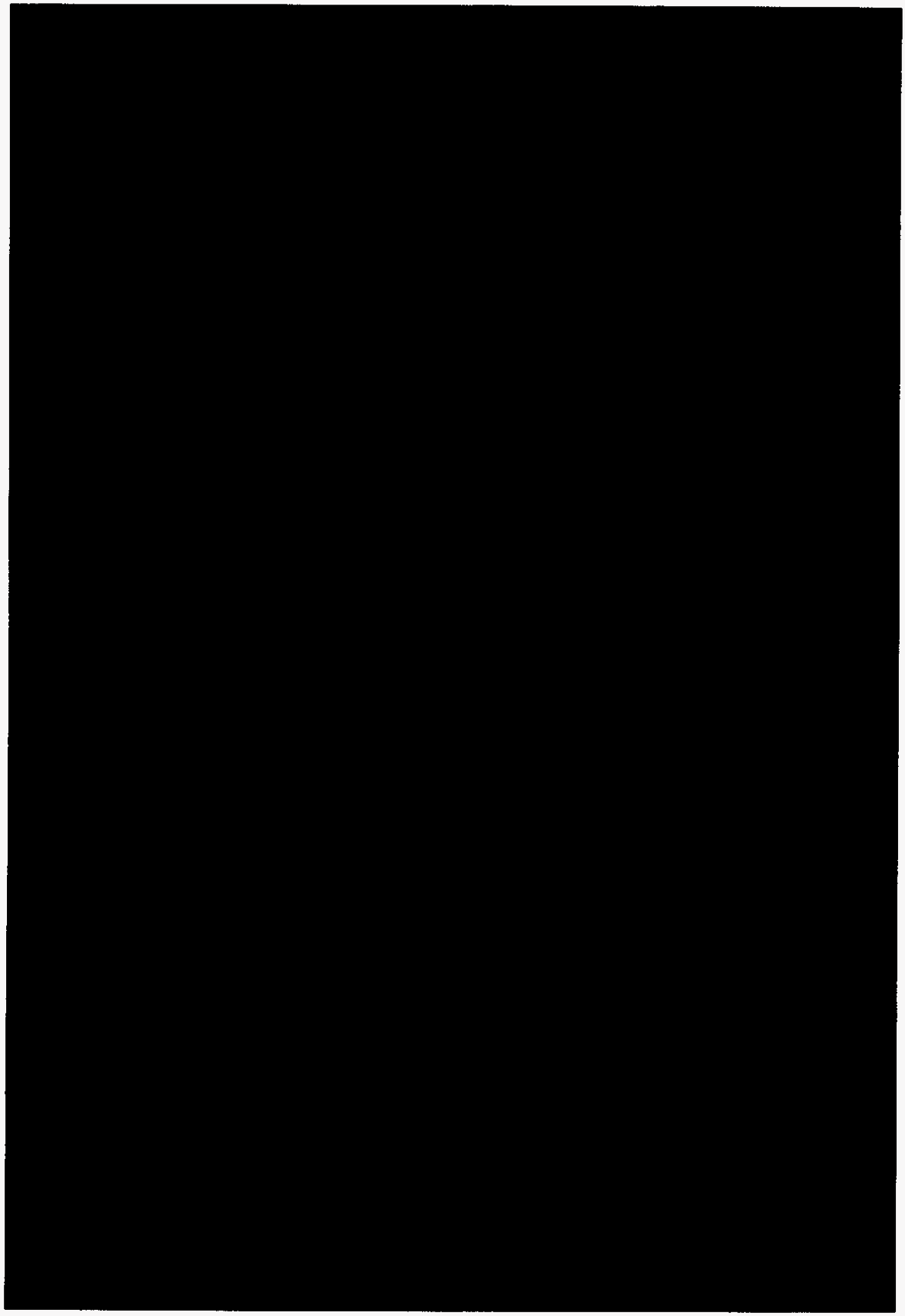


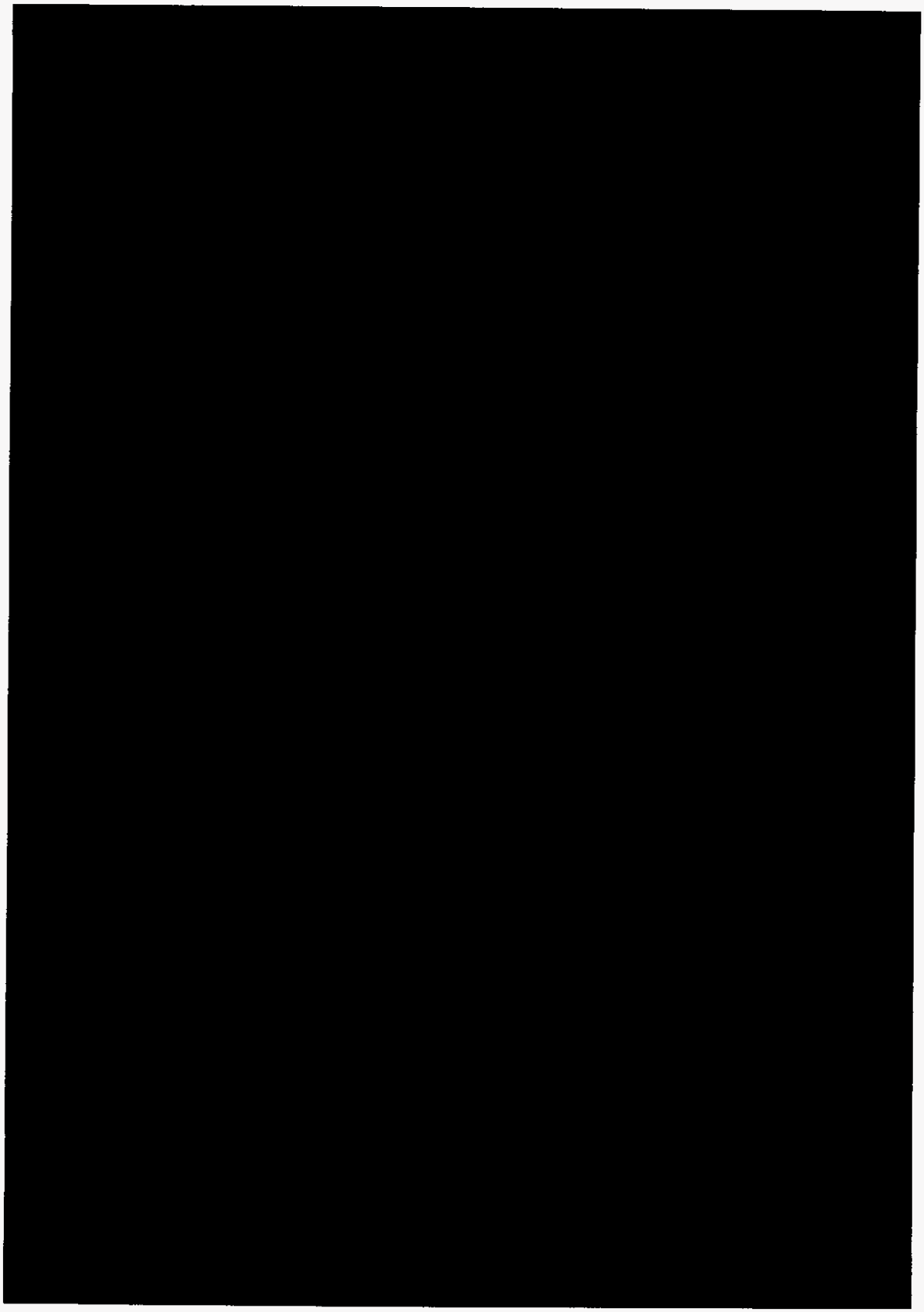


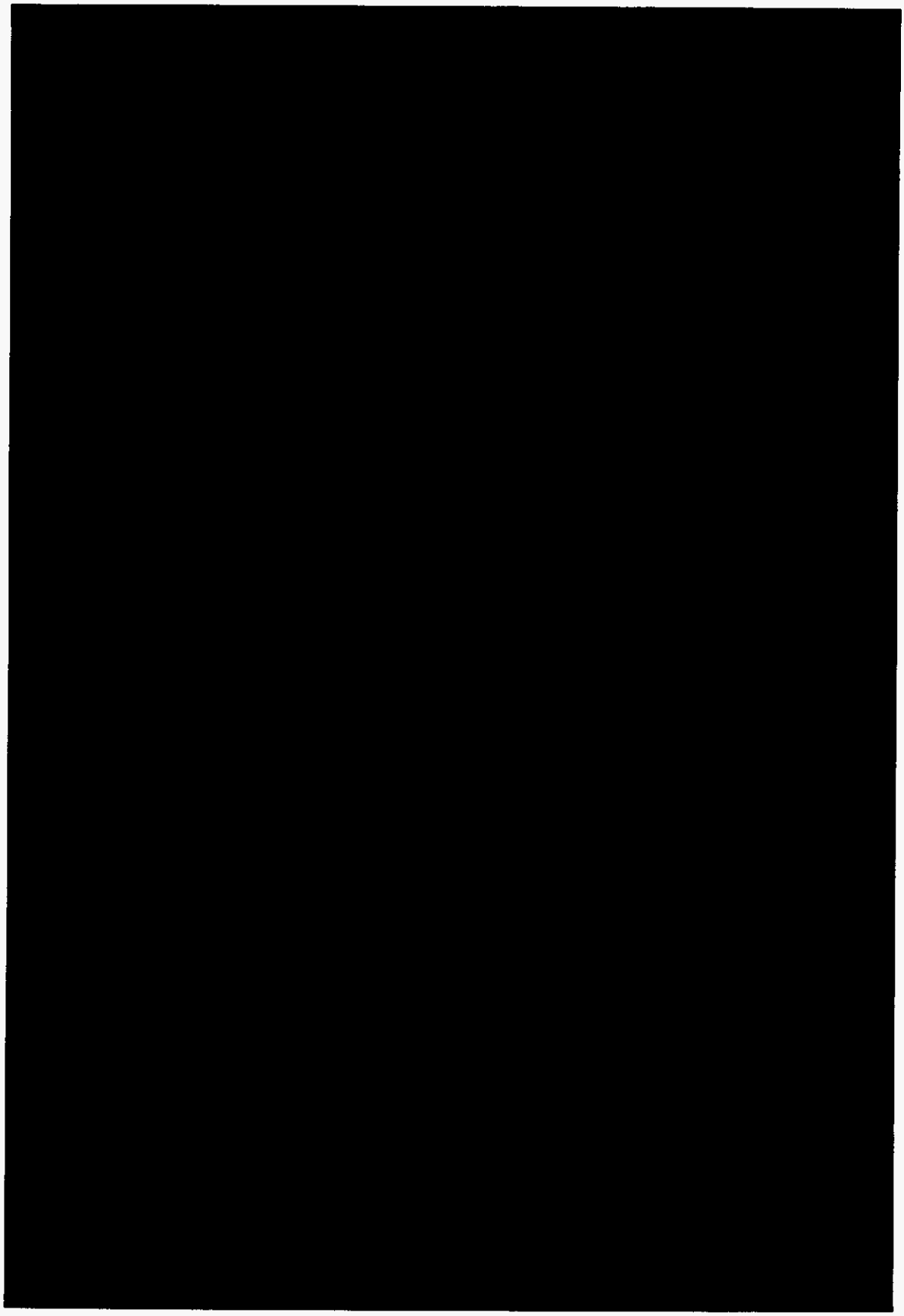


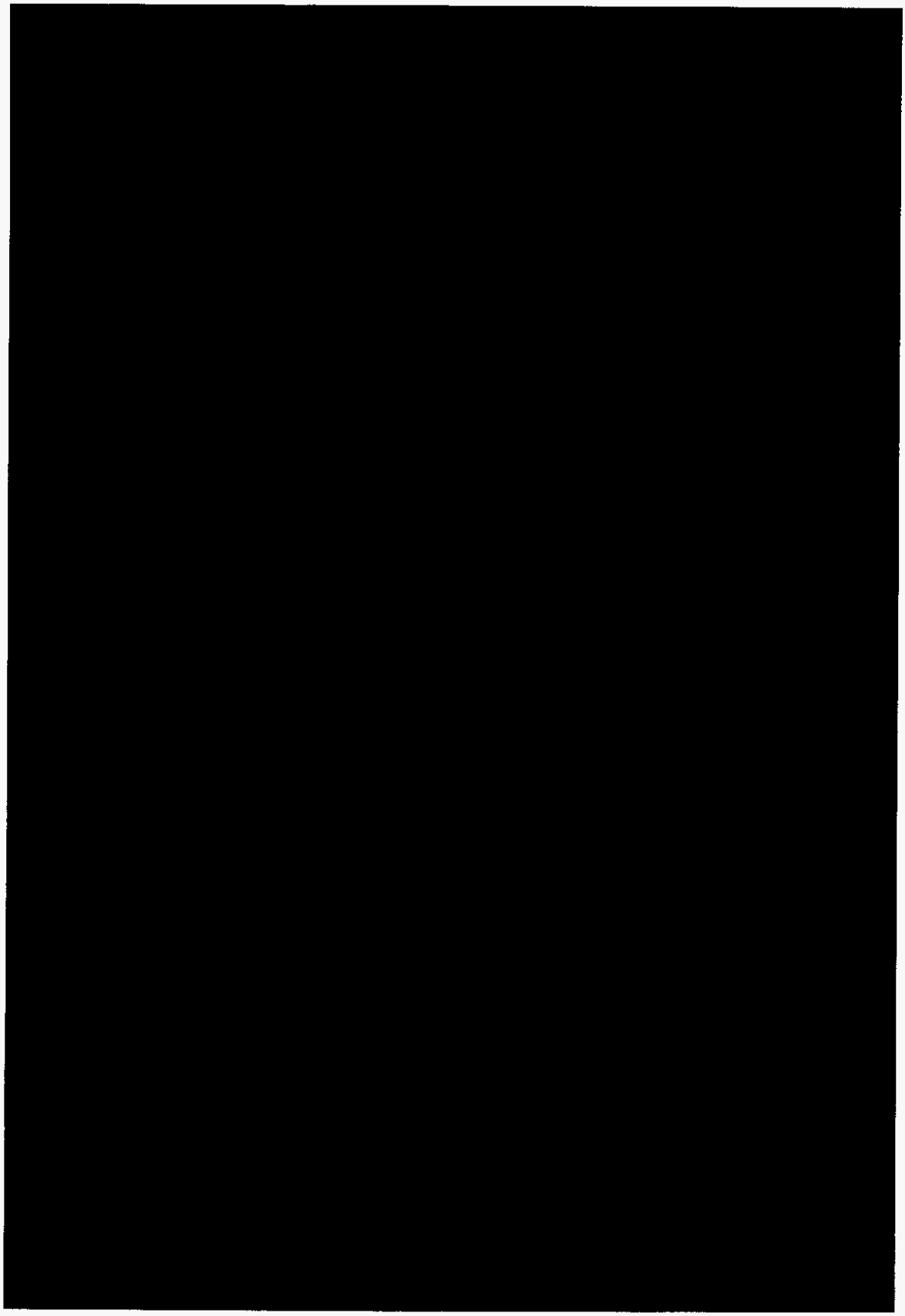


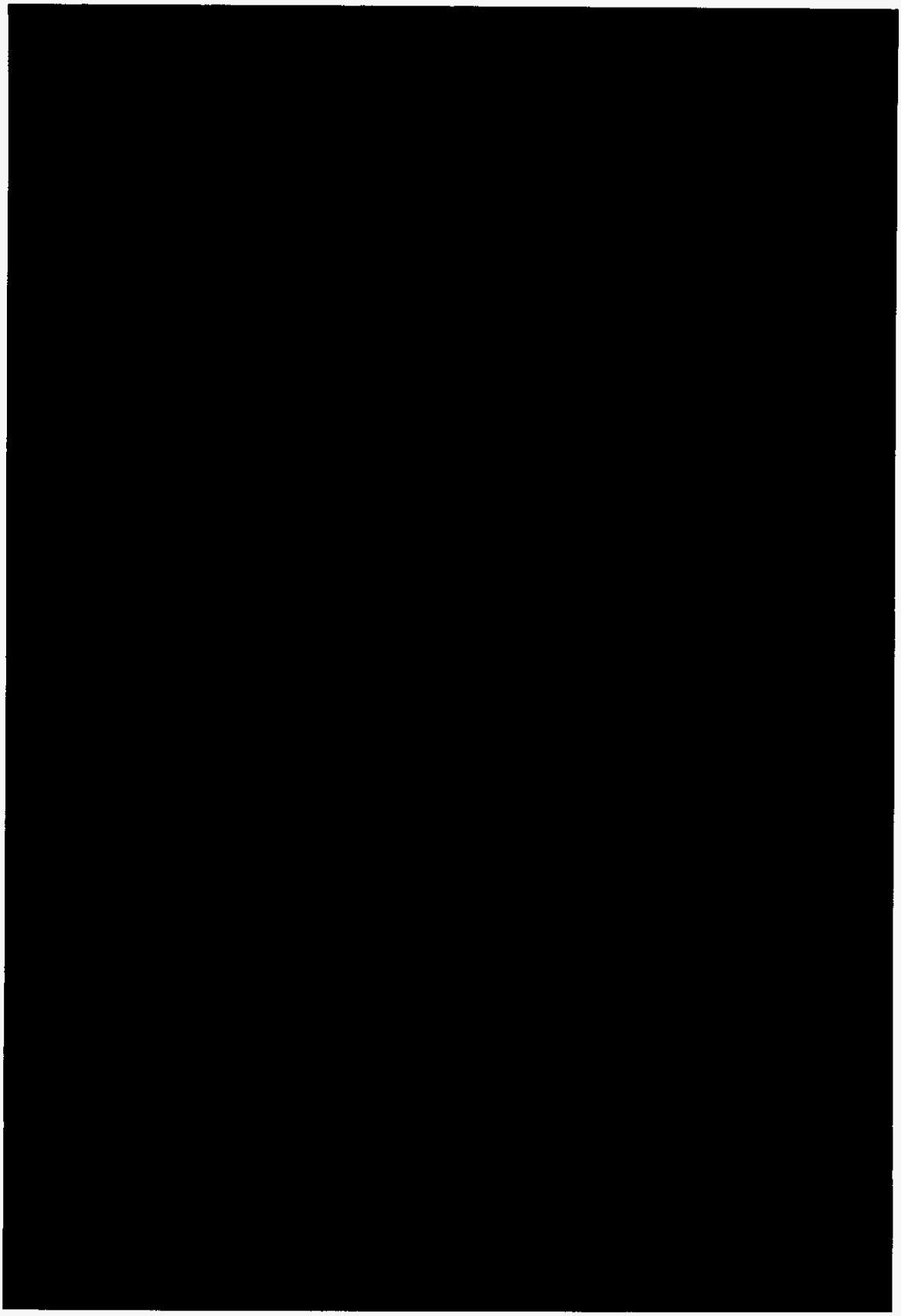


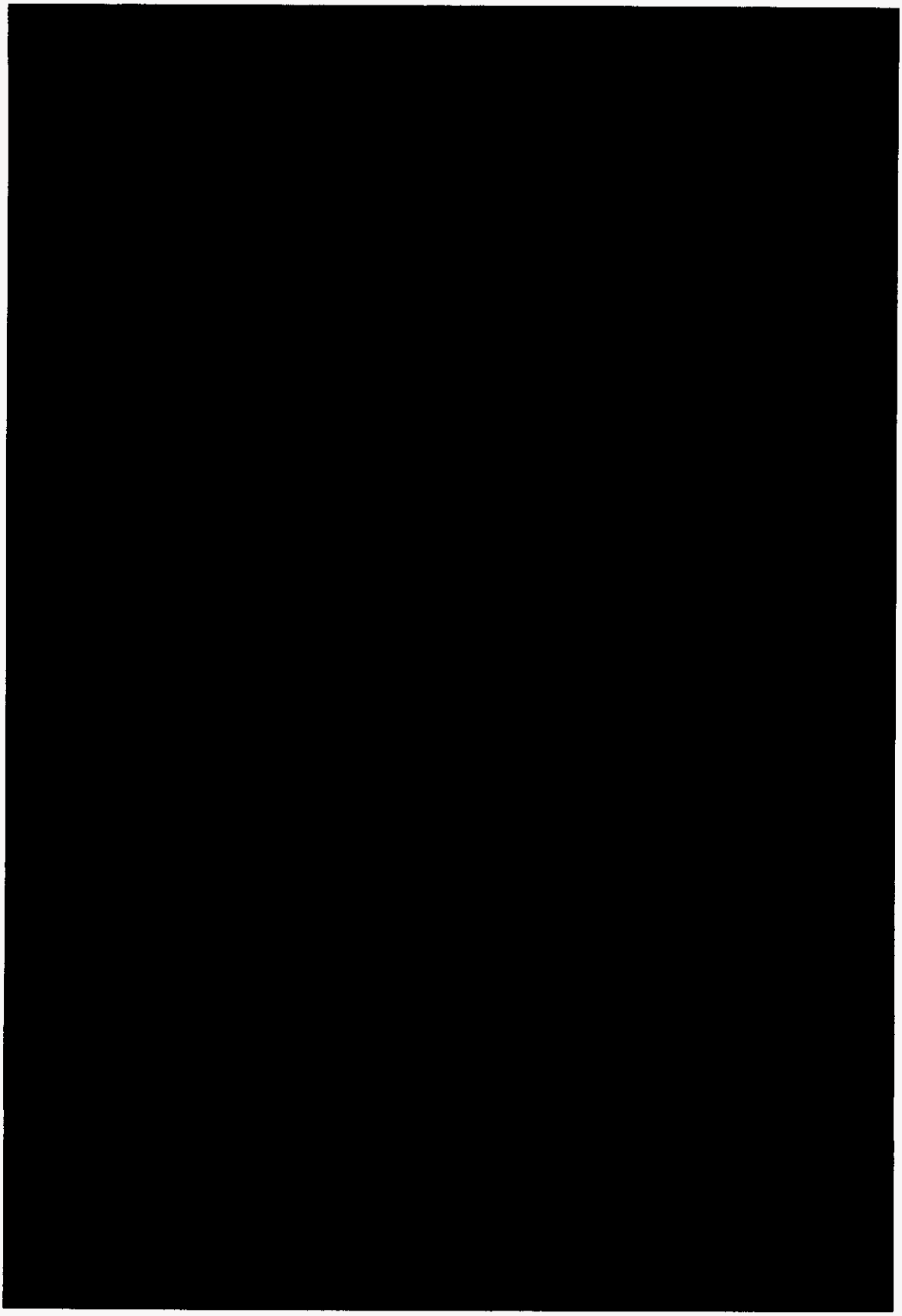


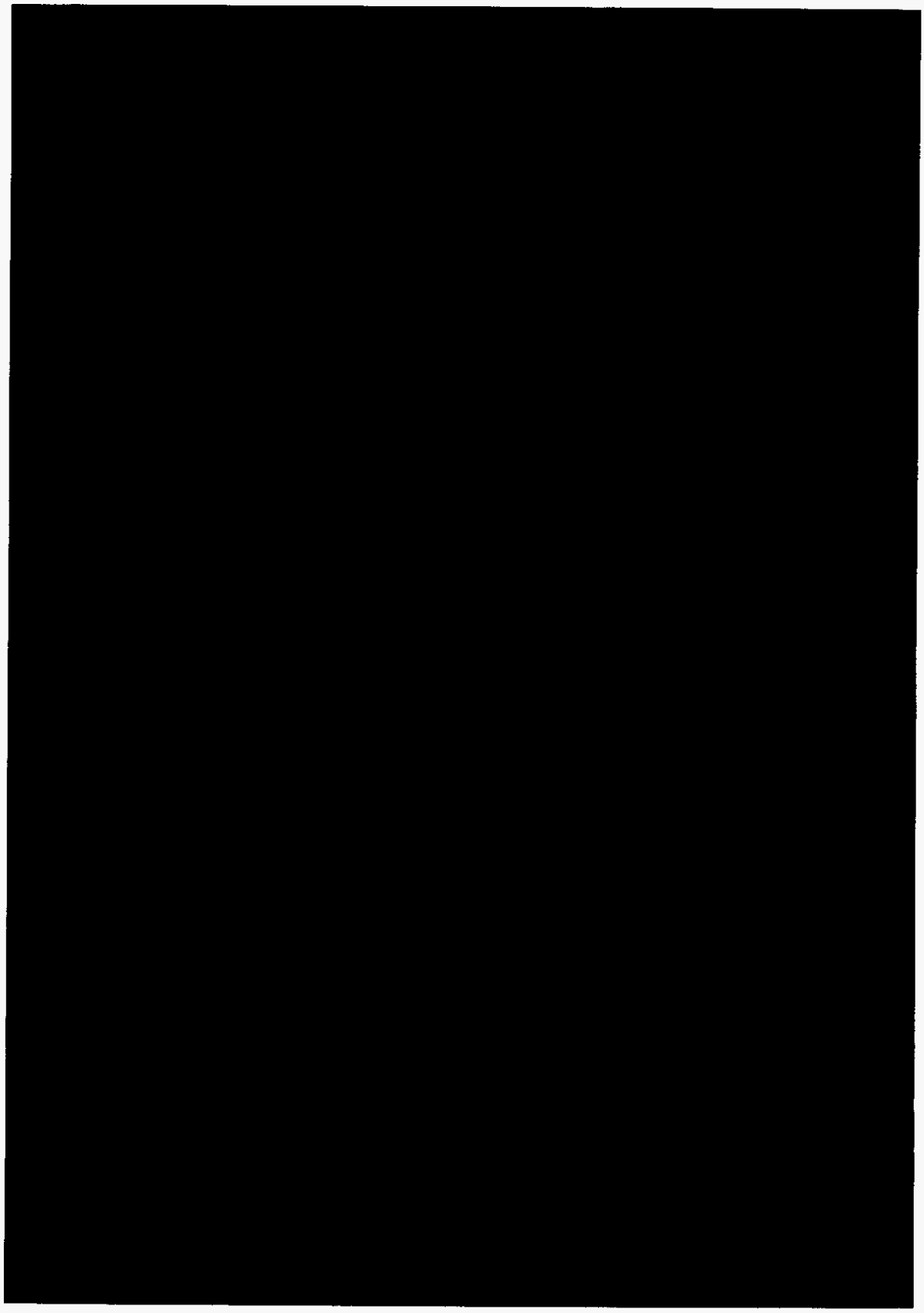


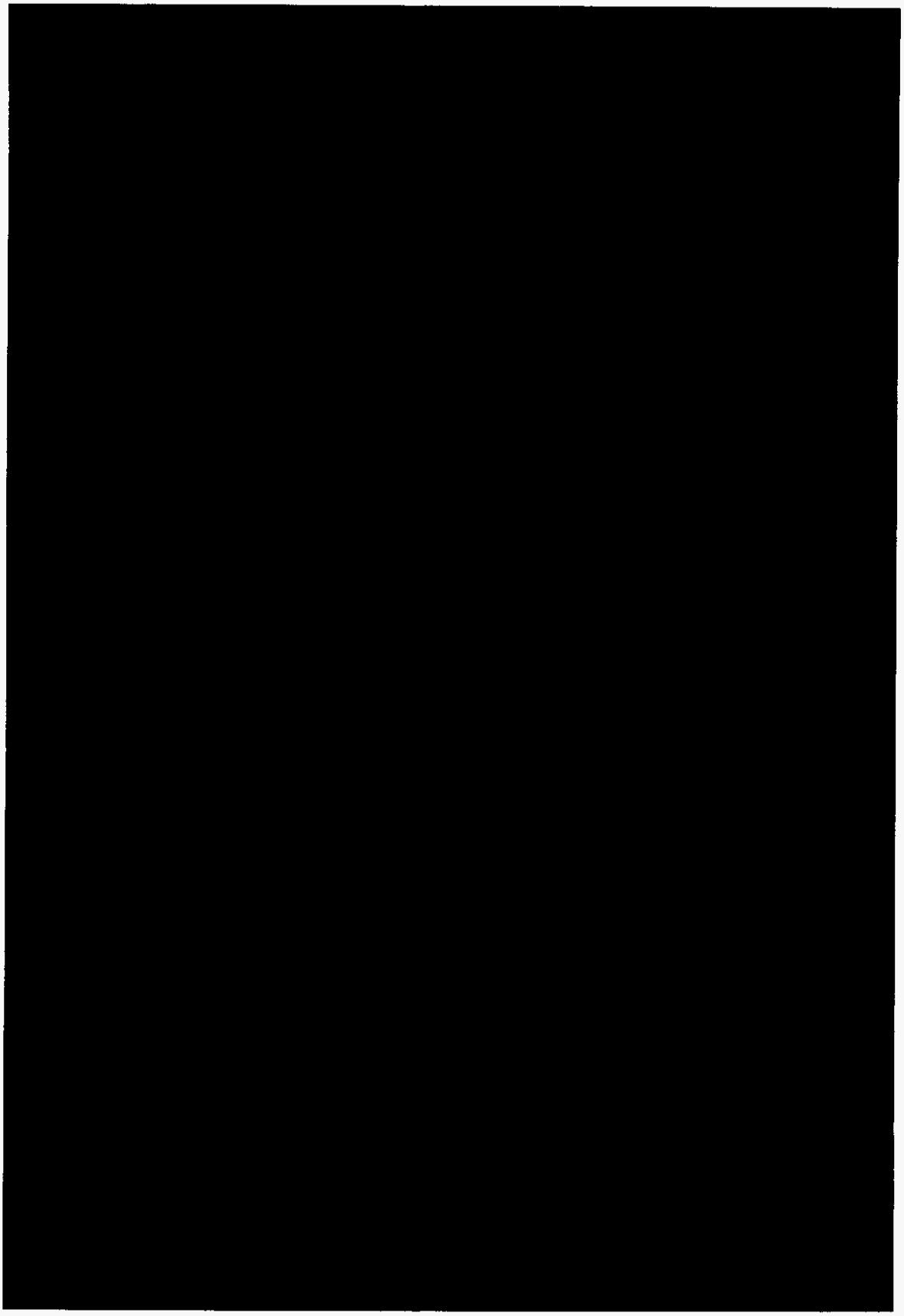


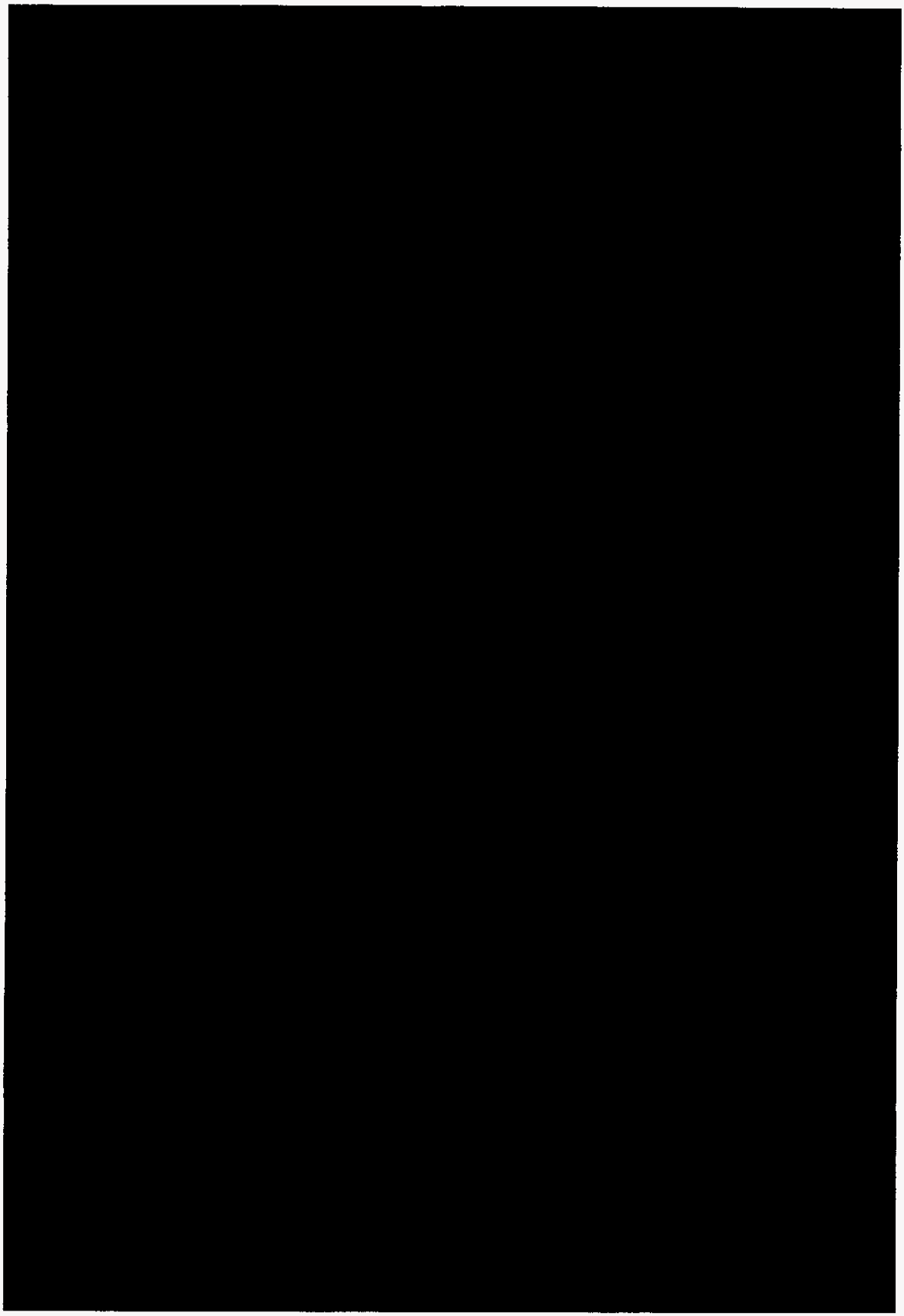


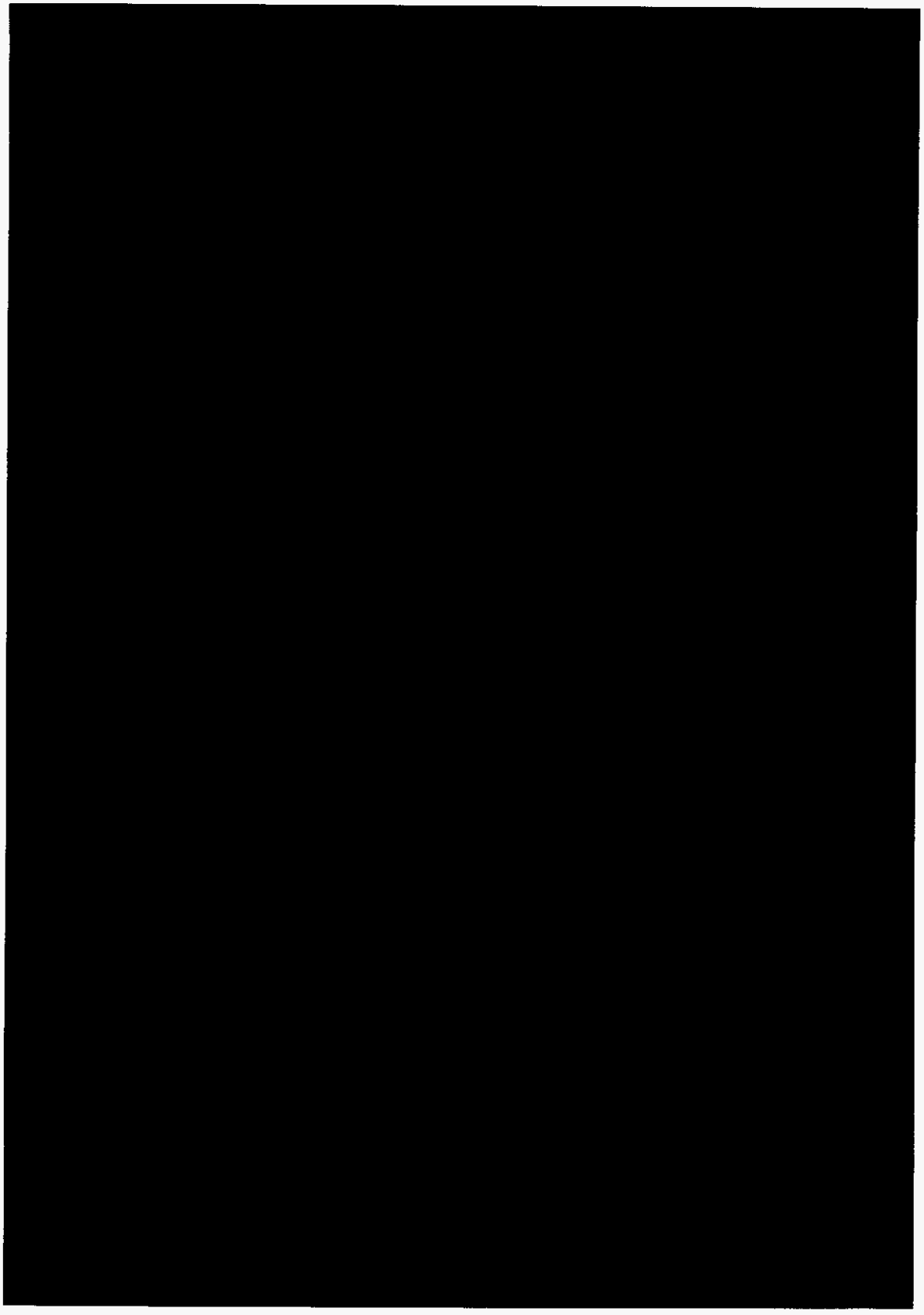


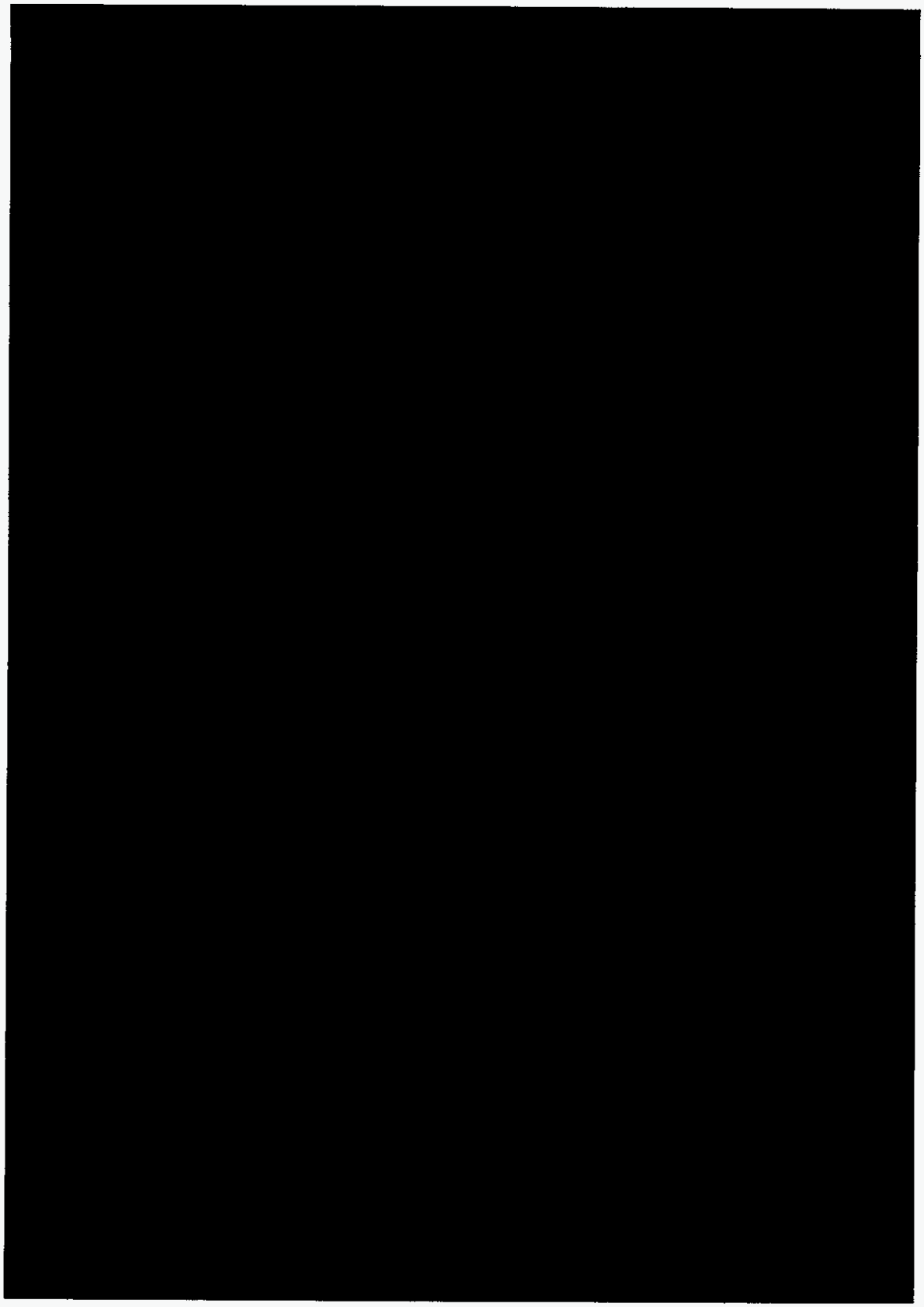


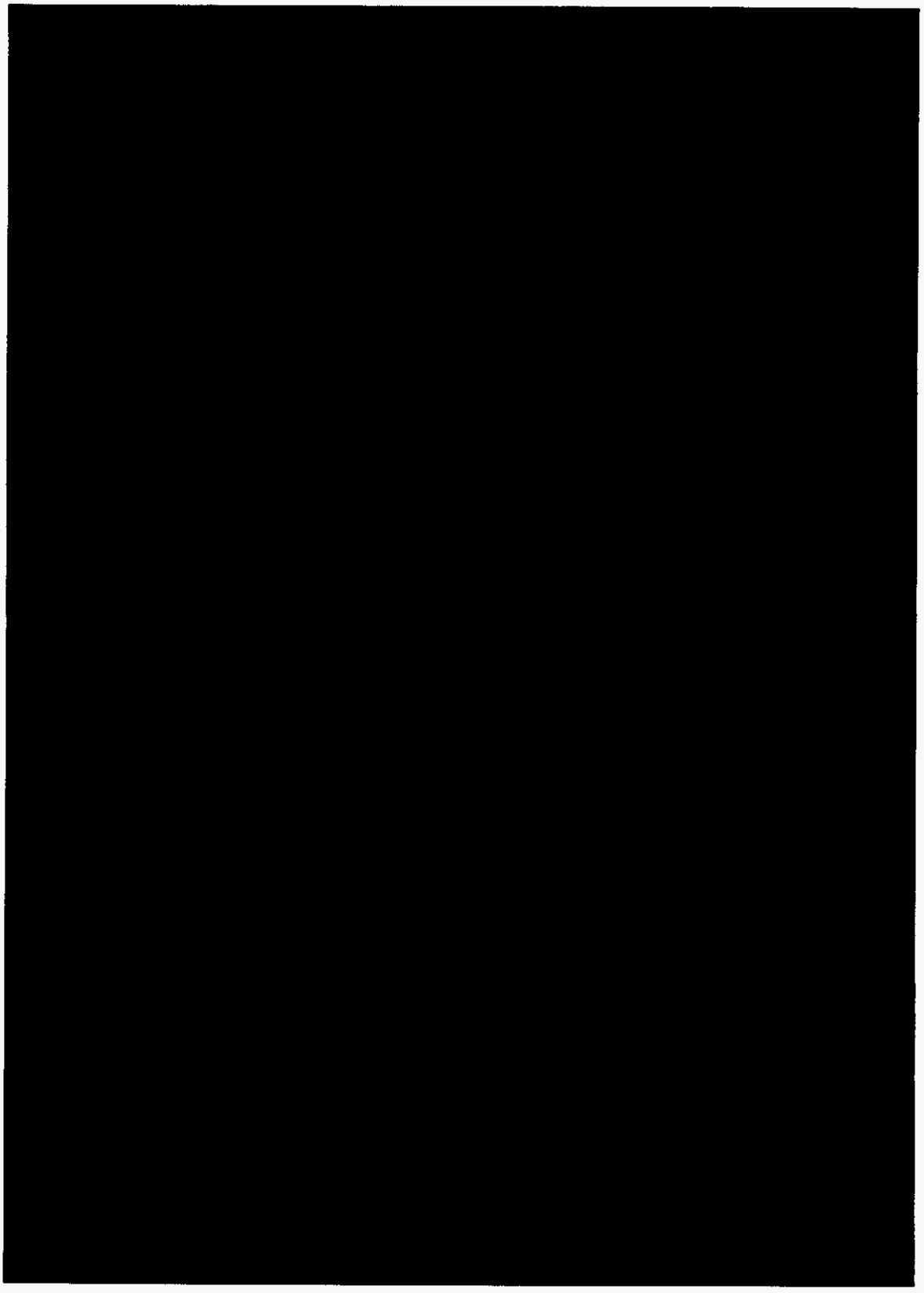


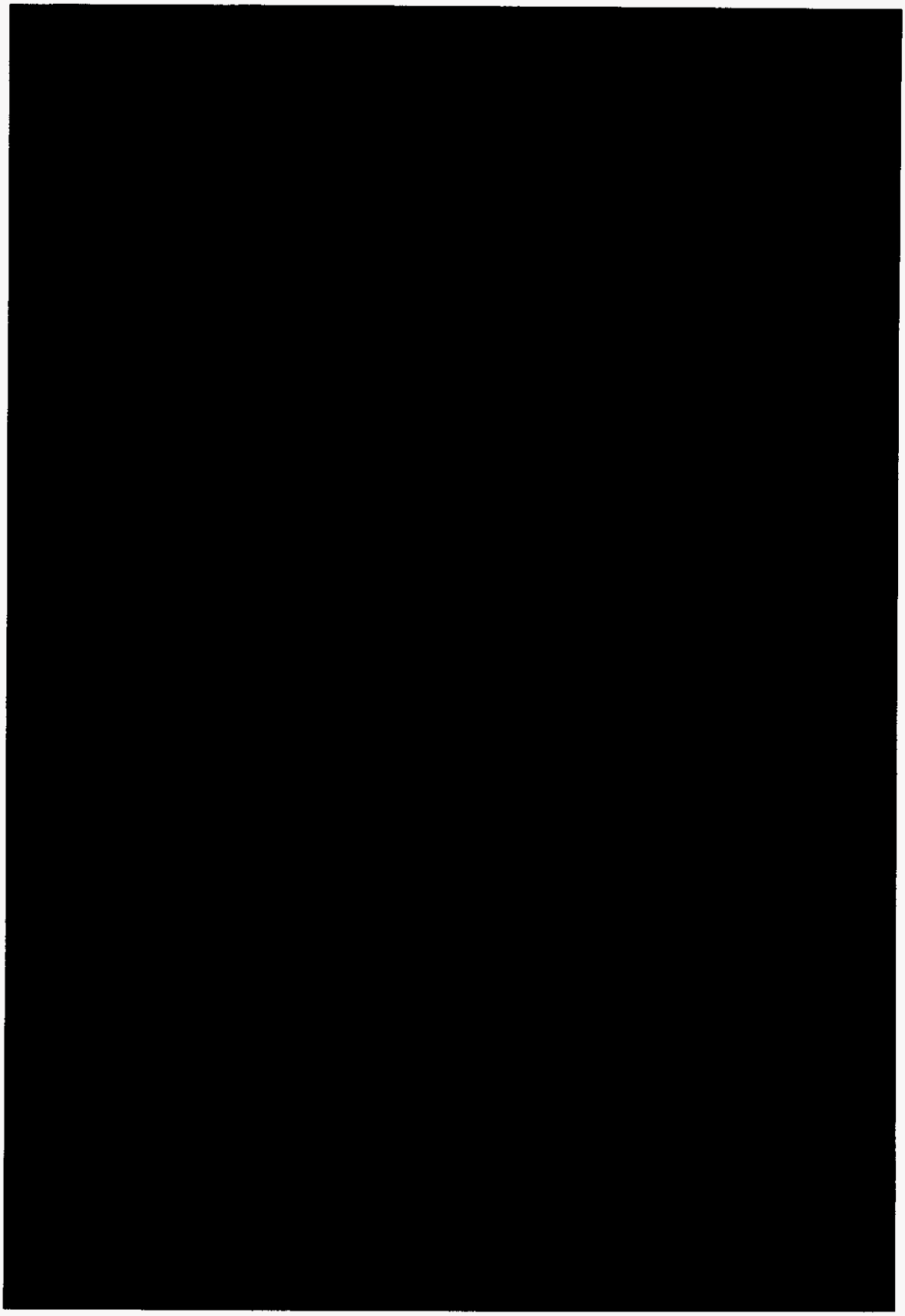


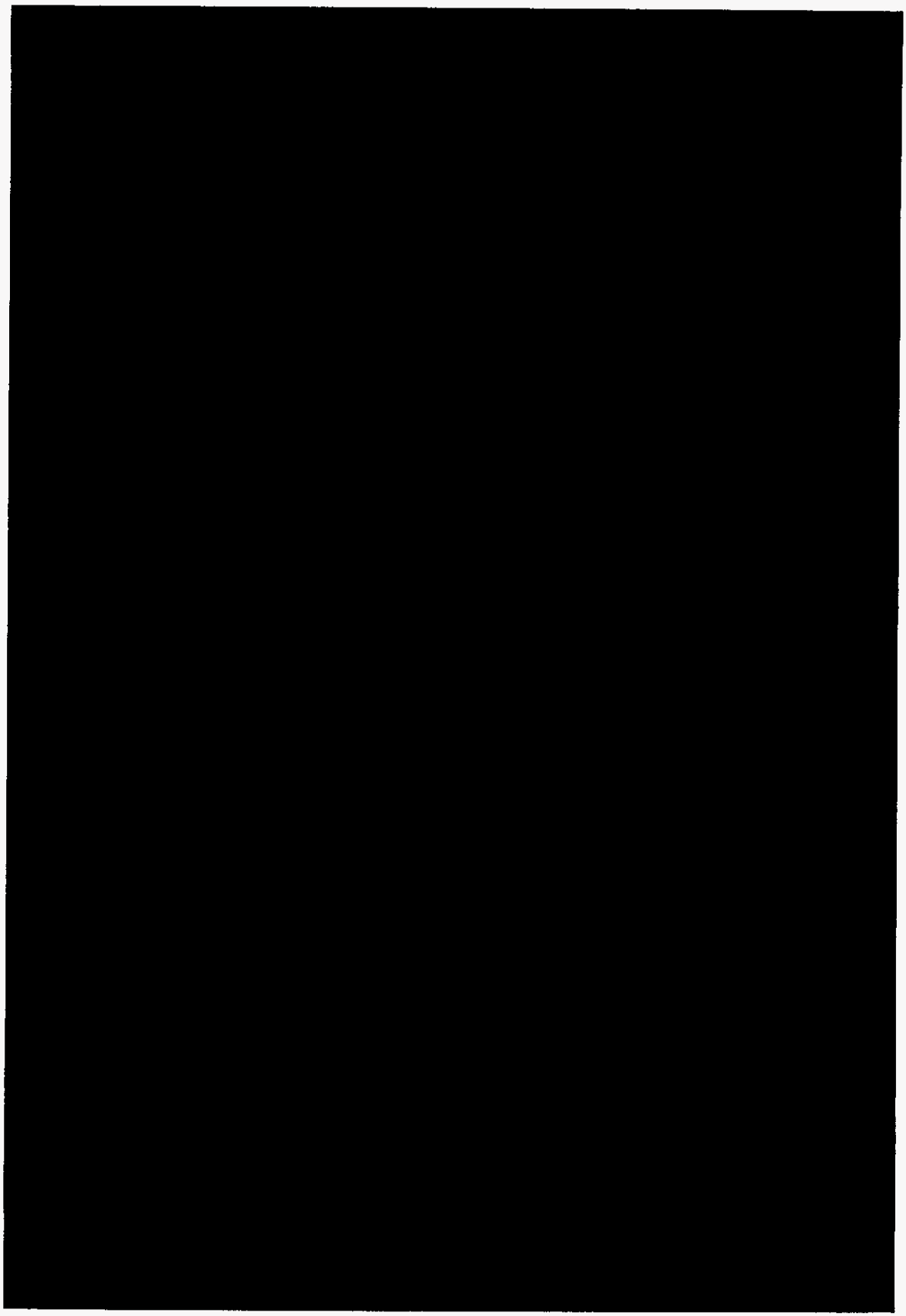


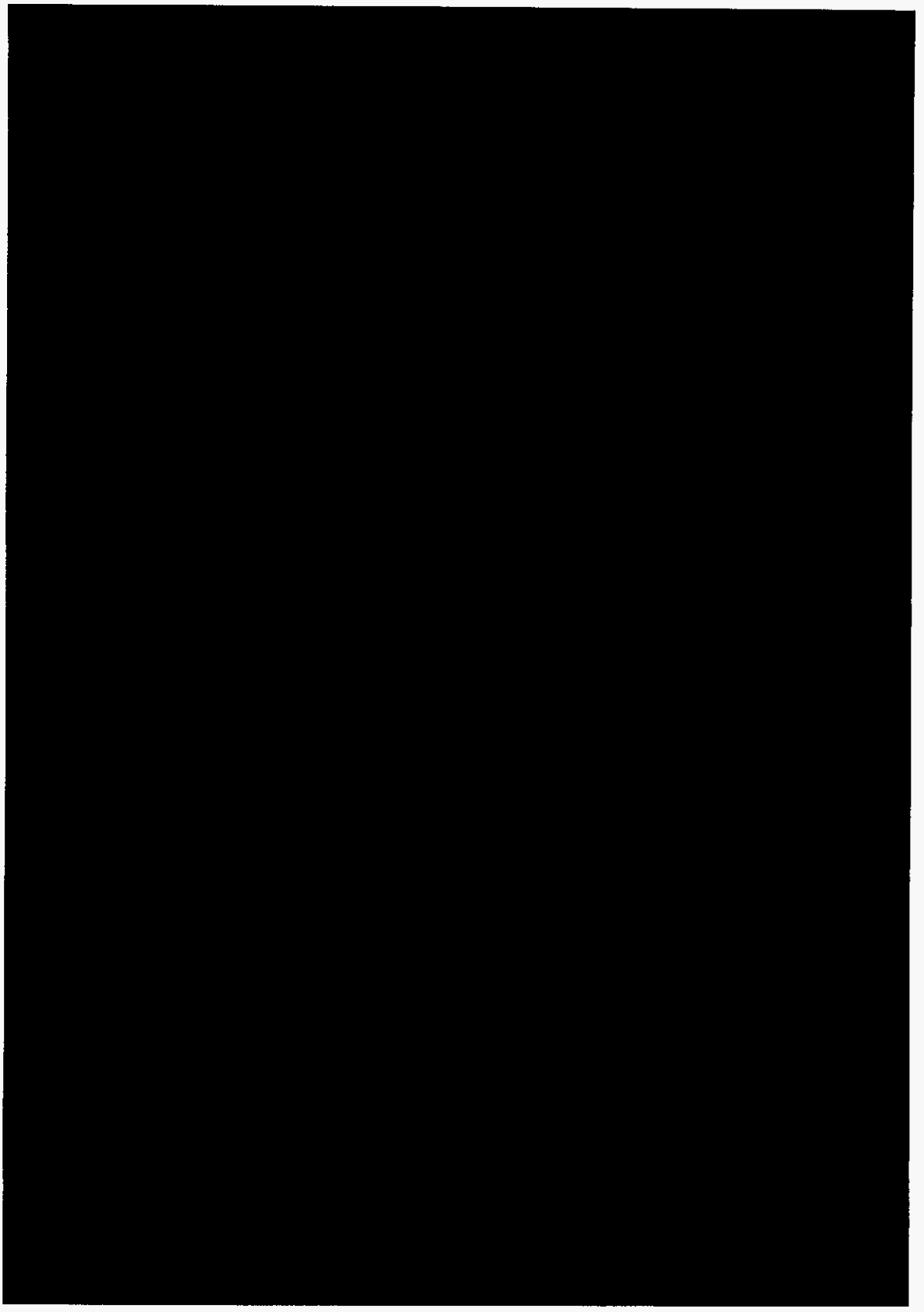


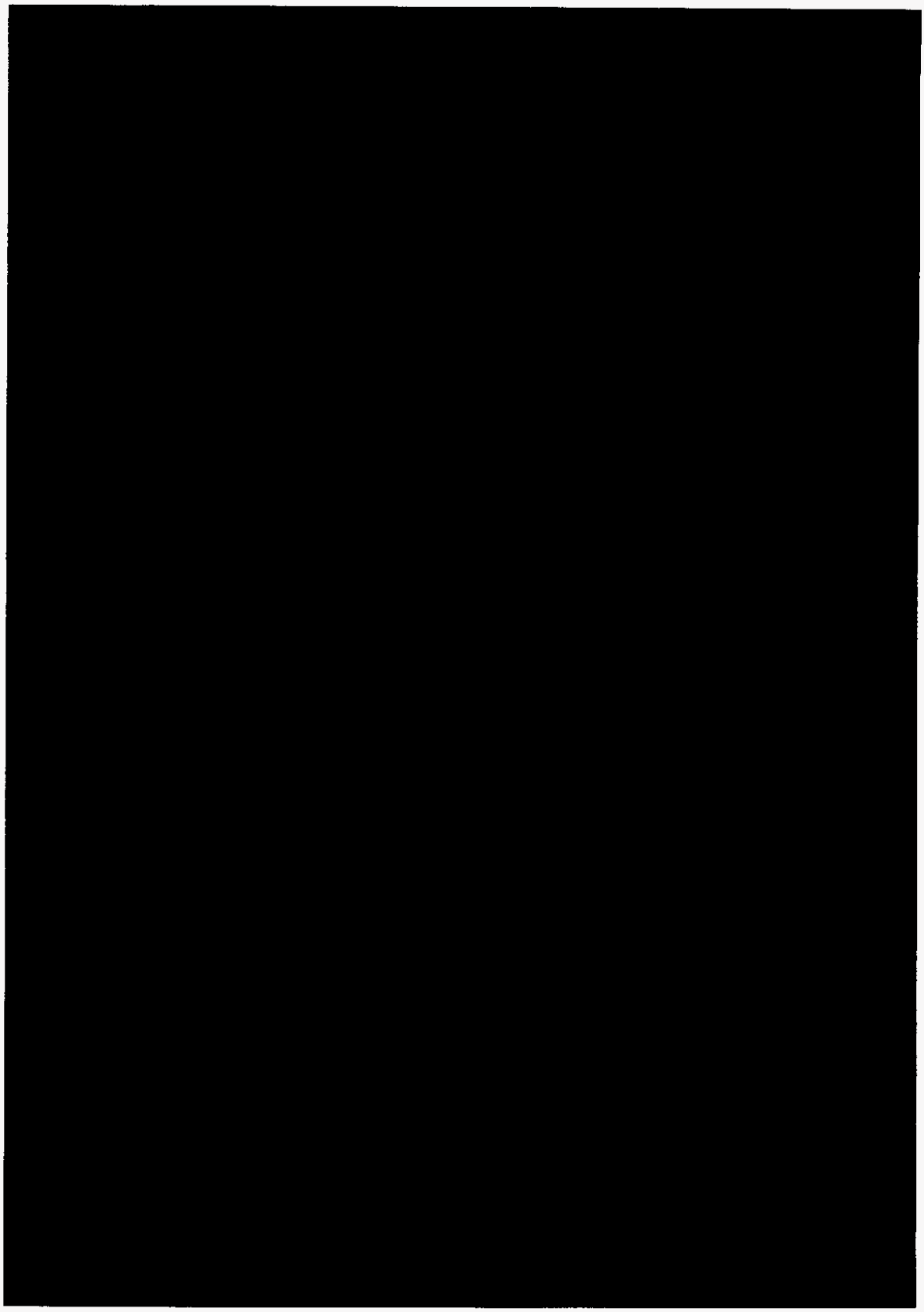


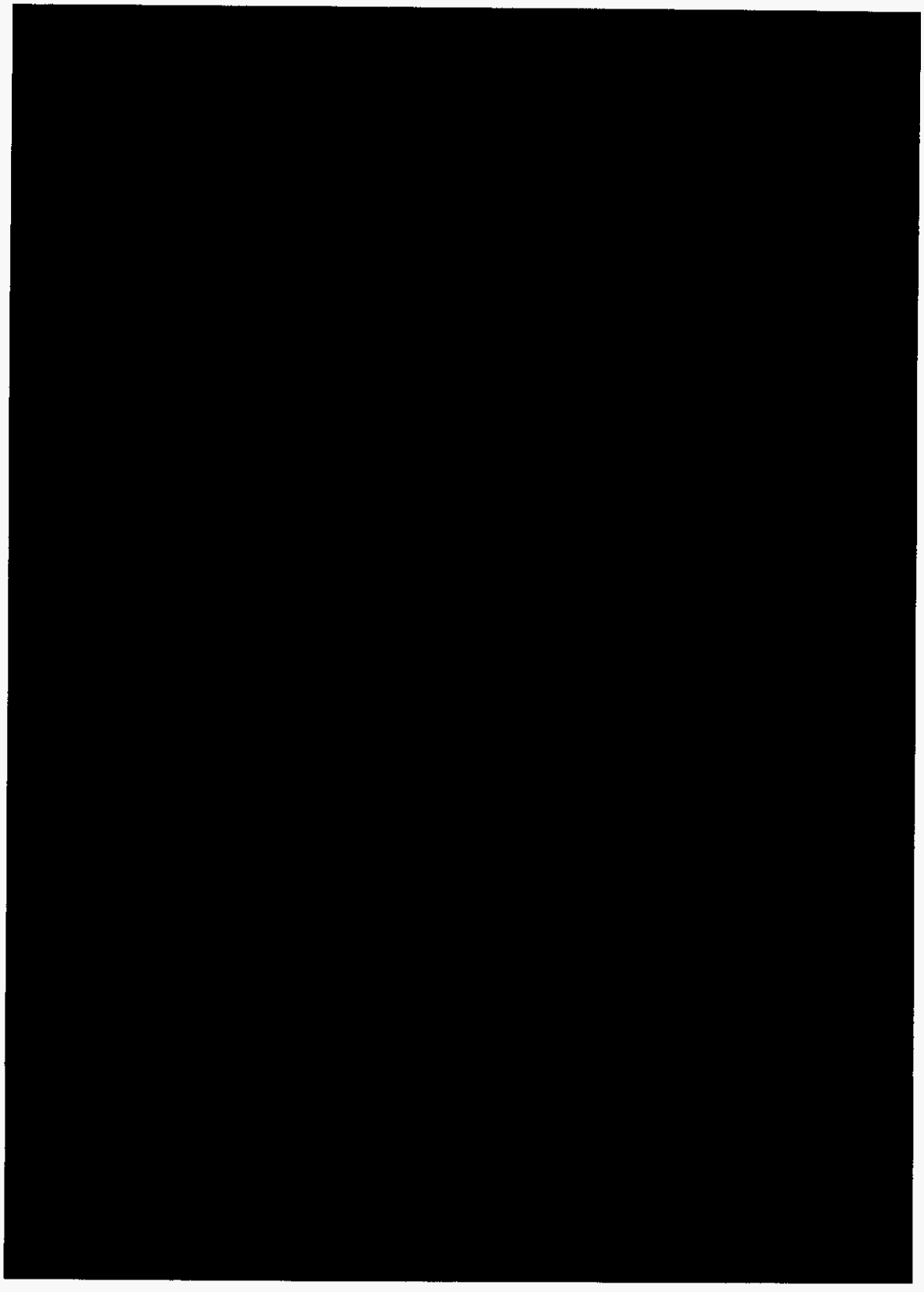


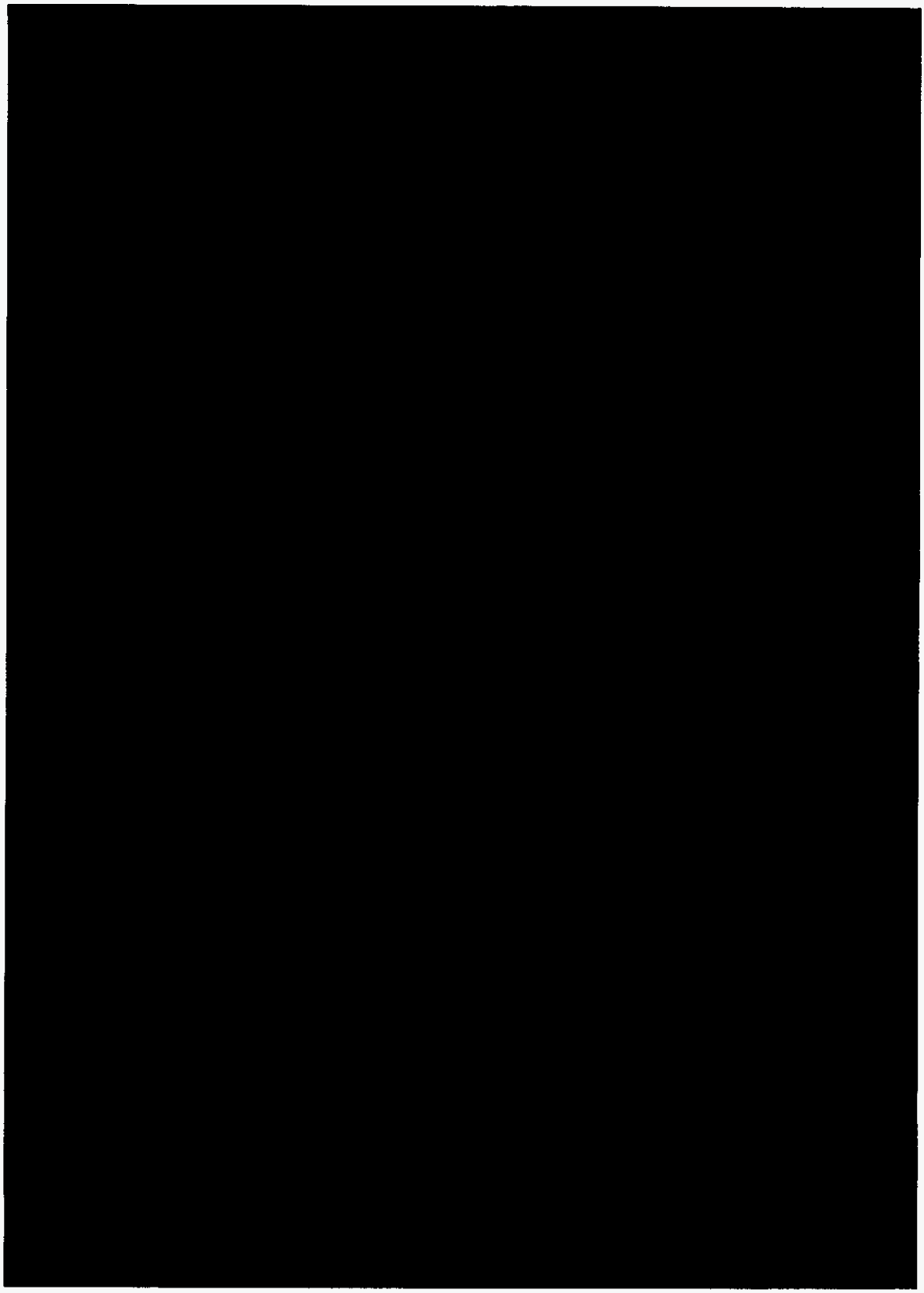


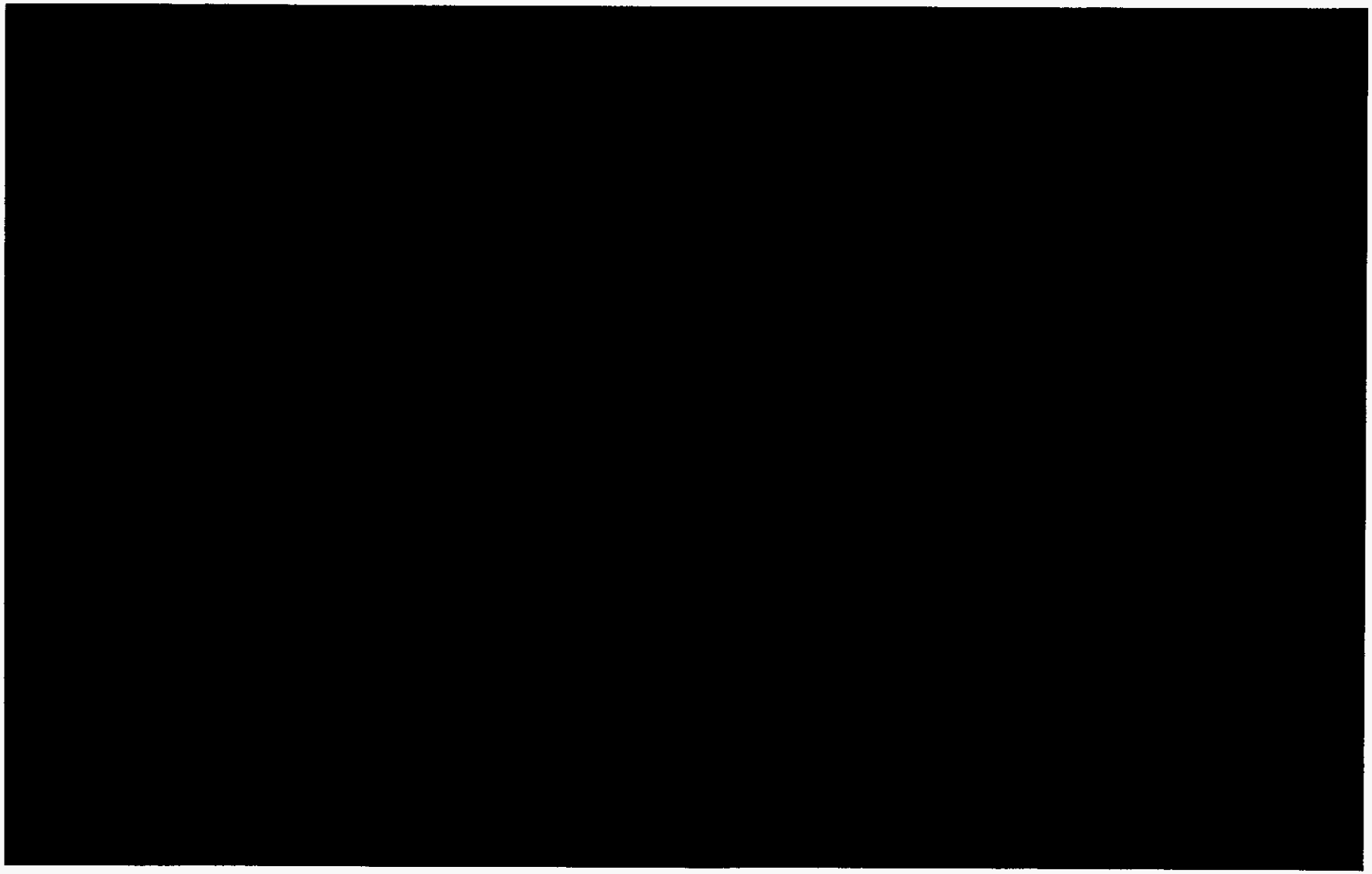


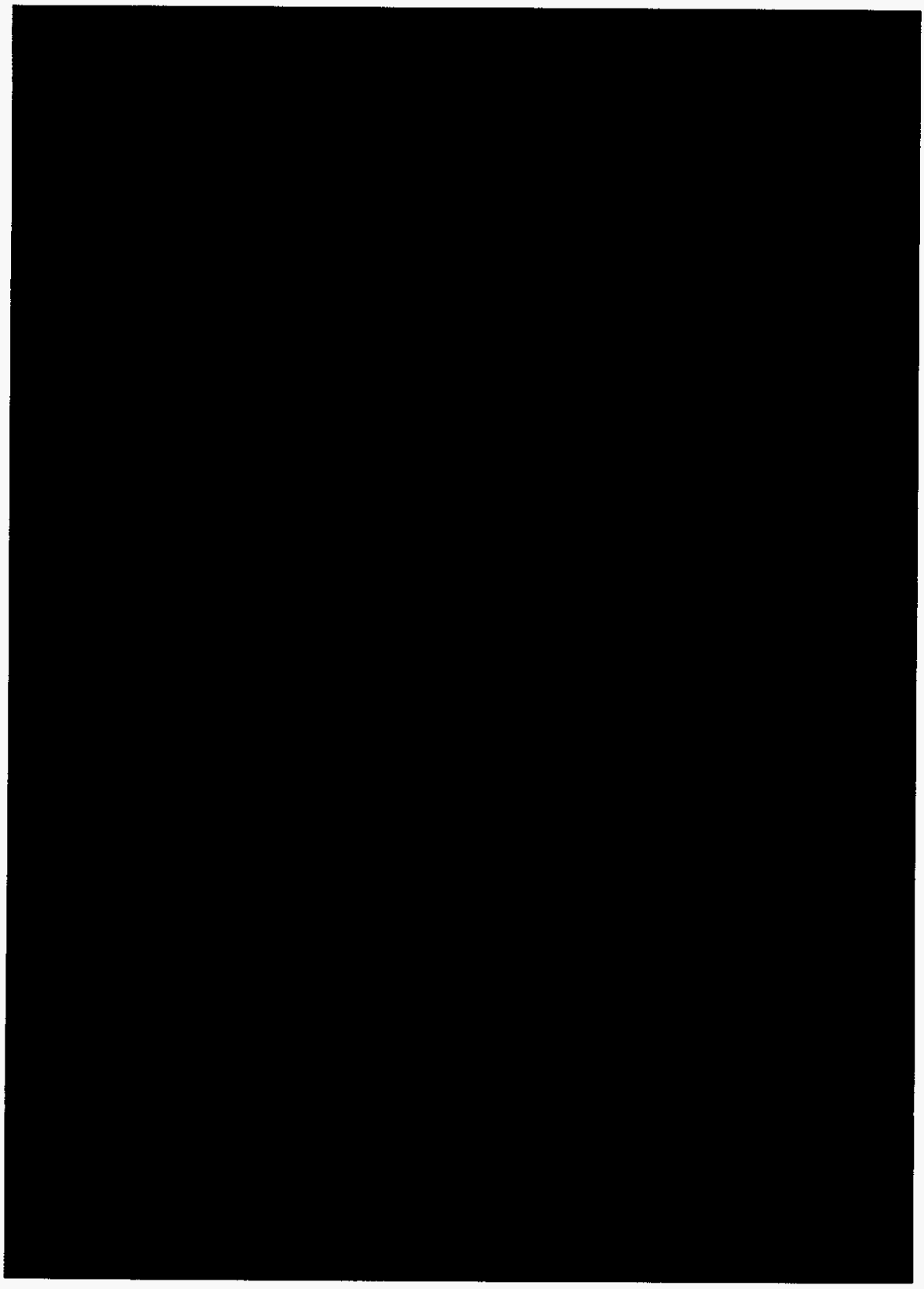












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT FRANKLIN UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. _____ EXHIBIT NO. _____
COMPANY/
WITNESS: _____
DATE: _____

CONFIDENTIALITY
DESIGNATION REVISED
11/2/2004

TLH-3
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT _____
SEPTEMBER 9, 2004

overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than 90 Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than 180 Days

after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party

shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of

times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

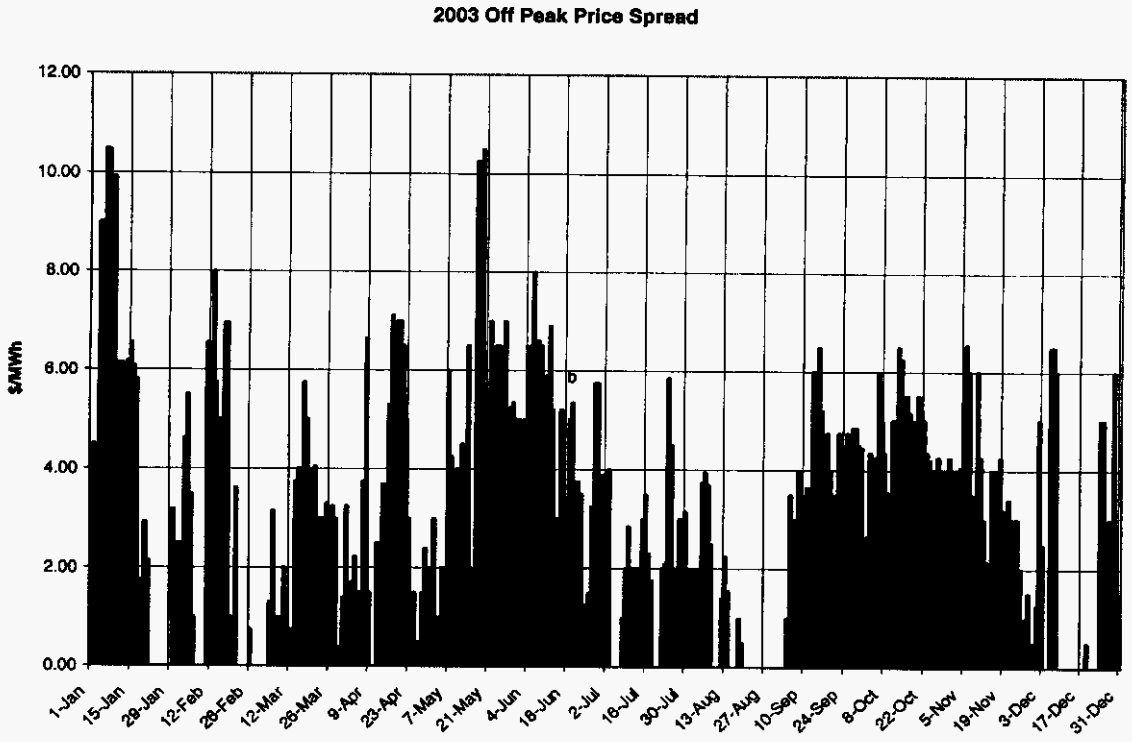
ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller

2003 off peak price spread between Florida and Southeastern SERC



TLH-4
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 16
COMPANY/ F.P.+L.
WITNESS. T. L. Hartman (TLH-4)
DATE: 11-08-04

Merchant Plants

Owner	Plant	Capacity	State		Notes
Simple Cycle Plants					
FPL Energy	Calhoun	668	AL		
Southern Co.	Greene County	740	AL		
Duke Energy	Sandersville	640	GA		
NRG Energy	Sterling	202	LA	]	
NRG Energy	Bayou Cove	320	LA	|	
Duke Energy	New Albany	350	MS	-	Must wheel through transmission constrained areas
Duke Energy	Southhaven	640	MS	|	
Duke Energy	Enterprise	640	MS	]	
Combined Cycle Plants					
In transmission constrained areas:					
Calpine	Pine Bluff	213	AR	]	
Cleco	Perryville	718	AR	|	
Duke Energy	Hot Springs	620	AR	-	Must wheel through transmission constrained areas
Mirant/Kinder	Wrightsville	550	AR	|	
Teco Energy	Union	2,200	AR	]	
Calpine	Hog Bayou	246	LA	]	
Calpine	Carville	501	LA	|	
Calpine	Arcadia	1,160	LA	|	
Cleco	Evangeline	919	LA	|	
Cogentrix	Ouachita	816	LA	|	
Cogentrix	Caldonia	810	MS	|	
Cogentrix	Southhaven	810	MS	-	Must wheel through transmission constrained areas
Duke Energy	Hinds	520	MS	|	
Intergen	Magnolia	900	MS	|	
NEGT	Attala	526	MS	|	
NRG Energy	Batesville	837	MS	]	
Reliant	Choctaw County	804	MS	]	
Southern Co.	Daniel	1,064	MS	]	
Extra Wheel					
Calpine	Decatur	792	AL	—	Connect to TVA
Calpine	Morgan	807	AL	—	Connect to TVA
Duke Energy	Murray	1,240	GA	—	Half under contract to Ga Power, remainder transmission constrained, need to wheel through Dalton, TVA, and Southern
Viable Alternatives					
Southern Co.	Barry	1,064	AL		
Southern Co.	Franklin	1,185	AL	—	Current offer
Southern Co.	Harris	1,254	AL	—	Current offer
Tenaska	Lindsey Hill	845	AL	—	Under contract until 2020 to Coral
Tenaska	Central Alabama	885	AL	—	Under contract until 2020 to Williams
Total		26,486			

TLH-5
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 17
COMPANY/ FPL
WITNESS: T. L. Hartman (TLH-5)
DATE: 11-08-04

Economic Analysis Against 2003 RFP Plant

SoCo Offer Economic Comparison to 2003 RFP Plant
(millions, NPV, 2004$, 2004 - 2032)

Description of Options	MW	Effective FPL Border Costs	Trans. Related Costs	Net Equity Adj.	Total	Difference from 2003 RFP Plant
Southern Company Offer						
Average Arbitrage	955	64,301	127	17	64,445	(28)
Minimum Arbitrage	955	64,325	127	17	64,468	(4)
Maximum Arbitrage	955	64,278	127	17	64,421	(51)
Comparison:						
2003 RFP Plant	1,220	64,342	73	58	64,473	

TLH-6
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 18
COMPANY/ F.P.+L.
WITNESS: T. L. Hartman (TLH-6)
DATE: 11-08-04

Timeline for Firm Transmission Service

Milestone Schedule for Obtaining Transmission

	Milestone	Maximum Duration	Maximum Cumulative Days	Tariff Reference
FPL	Request for service	0	0	
Southern	System Impact Study Agreement	30	30	19.1
FPL	Response	15	45	19.1
Southern	System Impact Study	60	105	19.3
FPL	Response	15	120	19.3
Southern	Facilities Study Agreement	30	135	19.4
FPL	Response	15	150	19.4
Southern	Facilities Study	60	210	19.4
FPL	Service Agreement	30	240	19.4

TLH-7
Docket No. 040001-EI
FPL Witness T. Hartman
Exhibit _____
October 18, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 19
COMPANY/ FP+L
WITNESS. T. L. Hartman (TLH-7)
DATE 11-08-04

SOUTHERN COMPANY TRANSMISSION QUEUE

TLH-8
Docket No. 040001-EI
FPL Witness T. Hartman
Exhibit_____
Pages 1-5
October 18, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 20
COMPANY/ FP+L
WITNESS: T. L. Hartman (TLH-8)
DATE 11-03-04

SOCO OASIS 1.4 - Status Query Results

Menus | Transmission | Offerings | Advanced Offerings | New Reservation | Status | Monitor | Query

Query Criteria
TS Class = Firm
Points Of Receipt = SOCO
Points Of Delivery = FPC, FPL, JEA, TAL
Path Name = SS/SOCO/SOCO-FL//
Service Period...
from 15-Oct-04 17:00 CD
to 15-Oct-21 18:00 CD

Status Info
Time of Query
15-Oct-04 16:03:24 CDT
44 Result Rows

Transmission Reservations where Customer and Seller are as selected

New Status	Status	ARef	Source / Sink	Begin Time	End Time	Requested Max Cap Sum:Avg	Granted Max Cap Sum:Avg	Offer Price	Bid Price	Price Units
	CONFIRMED	128534	UPS FPL	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	19 202:18	19 202:18	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:50 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to FPL incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128535	UPS FPC	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	7 74:6	7 74:6	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:52 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to FPC incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128536	UPS JEA	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	5 54:4	5 54:4	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:53 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to JEA incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128545	SCHERER4 FPL	01-Jan-00 01:00 CD	01-Jan-20 01:00 CD	38 760:38	38 760:38	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 12:09 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service Scherer4 to FPL incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128546	SCHERER4 JEA	01-Jan-00 01:00 CD	01-Jan-20 01:00 CD	12 240:12	12 240:12	16440.00	16440.00	$/MWyr
	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 12:10 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service Scherer4 to JEA incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	322721	BRANCH TAL	01-Jun-03 00:00 CD	01-Jun-23 00:00 CD	50 1000:50	19 19:0	21685.56	21685.56	$/MWyr
IMPACTED	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 12-Feb-02 17:21 CD							SWE/SOCO
			Expires 14-Mar-03 17:00 CD							Request Ref
			Status Comments Pursuant to terms of Service Agreement.							
			Seller Comments Yearly ATC based on monthly ATC, 6/1/03 to 6/1/04 - 1st year only							
			Check Ancillaries							
	STUDY	324518	WANSLEY FPL	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	1125 22500:1125	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller

			Time Queued Seller Comments		25-Feb-02 10:19 CD System Impact Study initiated					SWE/SOCO
	STUDY	324519	GOATROCK FPC	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	425 8500:425	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		25-Feb-02 10:19 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	324520	GOATROCK JEA	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	200 4000:200	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		25-Feb-02 10:20 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359209	BOWEN FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:30 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359210	BRANCH FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:30 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359211	SCHERER FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:31 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	403740	LLEA LLC TAL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403741	LLEA LLC TAL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403742	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403743	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403744	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403745	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403746	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403747	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	50 50:50	0 0:0	21685.56	21685.56	$/MWyr

		SOCO-FPC	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:55 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403748	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403749	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403750	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403751	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403752	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403753	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	50 50:50	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	CONFIRMED	478082	BRANCH TAL	01-Jun-04 00:00 CD	01-Jun-05 00:00 CD	19 19:19	19 19:19	21042.21	21042.21	$/MWyr
RENEWAL - Related Ref 322721 IMPACTED		SOCO-TAL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 29-Mar-04 09:14 CD Status Comments Pursuant to terms of Service Agreement. Seller Comments Yearly ATC based on monthly ATC, 6/1/04 to 6/1/05 Customer Comments Rollover Request of 322721 Check Ancillaries							Customer/Seller SWE/SOCO
	CONFIRMED	488588	YATES FPL	01-Jun-04 00:00 CD	01-Jun-05 00:00 CD	1 12:1	1 12:1	1753.52	1753.52	$/MWmo
IMPACTED		SOCO-FPL	Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 28-May-04 10:55 CD Seller Comments Not a real transaction. Customer Comments To permit correction of ATC due to contract adjustments Check Ancillaries							Customer/Seller SOCO/SOCO Deal Ref PSEUDO
	RECEIVED	505440	MILLER FPL	01-Jun-10 00:00 CD	01-Jun-15 00:00 CD	720 3600:720	0 0:0	21042.21	21042.21	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 13:47 CD Customer Comments ROLLOVER OF PRE-TARIFF UPS SERVICE							Customer/Seller FPLM/SOCO
	RECEIVED	505441	SCHERER FPL	01-Jun-10 00:00 CD	01-Jun-15 00:00 CD	210 1050:210	0 0:0	21042.21	21042.21	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 13:48 CD Customer Comments ROLLOVER OF PRE-TARIFF UPS SERVICE							Customer/Seller FPLM/SOCO
	RECEIVED	505443	HILLABEE FPL	01-Jun-10 00:00 CD	01-Jun-12 00:00 CD	700 1400:700	0 0:0			$/MWyr
REDIRECT - Related Ref 465863 Related POR/POD SOCO-GTC Related Sink OPCLOAD		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 14:14 CD Check Ancillaries							Customer/Seller CALP/SOCO

	STUDY	505590	MILLER TAL	01-Jul-05 00:00 CD	01-Sep-05 00:00 CD	50 100:50	0 0:0	1712.61	1712.61	$/MWmo
SOCO-TAL			Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 26-Aug-04 12:55 CD							Customer/Seller MSCG/SOCO	
	CONFIRMED	507786	HEARDCOTNSK FPL	01-Oct-04 00:00 CD	01-May-05 00:00 CD	66 462:66	66 198:28			$/MWmo	
SOCO-FPL REDIRECT - Related Ref 422069 Related POR/POD SOCO-EES Related Sink EES			Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 09-Sep-04 06:03 CD Expires 08-Oct-04 12:35 CD Seller Comments Please confirm or withdraw ASAP Check Ancillaries							Customer/Seller EXGN/SOCO Request Ref	
	RECEIVED	512147	MILLER FPL	01-Jan-05 01:00 CD	01-Jan-08 01:00 CD	100 300:100	0 0:0	20451.52	20451.52	$/MWyr	
SOCO-FPL			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 06-Oct-04 07:22 CD							Customer/Seller MSCG/SOCO	
	RECEIVED	512148	MILLER FPL	01-Jan-05 01:00 CD	01-Jan-08 01:00 CD	100 300:100	0 0:0	20451.52	20451.52	$/MWyr	
SOCO-FPL			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 06-Oct-04 07:22 CD							Customer/Seller MSCG/SOCO	
	CONFIRMED	513236	BRANCH TAL	15-Oct-04 00:00 CD	16-Oct-04 00:00 CD	19 19:19	19 19:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 14-Oct-04 10:22 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	513297	BRANCH TAL	18-Oct-04 00:00 CD	19-Oct-04 00:00 CD	19 19:19	19 19:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 15-Oct-04 12:22 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	513306	BRANCH TAL	16-Oct-04 00:00 CD	18-Oct-04 00:00 CD	19 38:19	19 38:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 15-Oct-04 14:27 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	90100	SOCO FPC	01-Mar-97 01:00 CD	01-Mar-13 01:00 CD	10 160:10	10 160:10	16440.00	16440.00	$/MWyr	
SOCO-FPC IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-97 01:00 CD Customer Comments Prior Service SOCO to Bay County							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90110	UPS FPL	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	921 11052:921	921 11052:921	16440.00	16440.00	$/MWyr	
SOCO-FPL IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to FPL							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90120	UPS FPC	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	409 4908:409	409 4908:409	16440.00	16440.00	$/MWyr	
SOCO-FPC IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to FPC							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90130	UPS JEA	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	205 2460:205	205 2460:205	16440.00	16440.00	$/MWyr	
SOCO-JEA IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to JEA							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90150	SCHERER4 FPL	01-Jan-99 01:00 CD	01-Jan-20 01:00 CD	649 13629:649	649 13629:649	16440.00	16440.00	$/MWyr	
SOCO-FPL IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD							Customer/Seller SOCO/SOCO	

			Customer Comments		Prior Service Scherer4 to FPL					Deal Ref PRIOR
	CONFIRMED	90160	SCHERER4 JEA	01-Jan-99 01:00 CD	01-Jan-20 01:00 CD	201 4221:201	201 4221:201	16440.00	16440.00	$/MWyr
IMPACTED		SOCO-JEA	Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller SOCO/SOCO
			Time Queued		01-Jan-99 01:00 CD					Deal Ref PRIOR
			Customer Comments		Prior Service Scherer4 to JEA					

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003)(Estimated)	$	(854,985)

Exhibit No._____
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Florida Public Utilities Company
(GMB-1)
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 21
COMPANY/ FPUC
WITNESS: George M. Bachman (GMB-1)
DATE: 11-05-04

DOCUMENT NUMBER-DATE
08709 AUG 10 04
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Schedule E1-B

MARIANNA DIVISION

			ACTUAL JANUARY 2004	ACTUAL FEBRUARY 2004	ACTUAL MARCH 2004	ACTUAL APRIL 2004	ACTUAL MAY 2004	ACTUAL JUNE 2004	Estimated JULY 2004	Estimated AUGUST 2004	Estimated SEPTEMBER 2004	Estimated OCTOBER 2004	Estimated NOVEMBER 2004	Estimated DECEMBER 2004	Total
Total System Sales - KWH			28,916,312	25,785,248	23,223,450	21,415,624	21,896,946	28,005,951	25,222,653	25,207,331	25,233,533	25,238,941	25,224,964	25,252,262	300,623,235
Total System Purchases - KWH			29,069,532	26,131,216	22,273,650	22,185,213	27,989,514	30,623,247	30,965,000	30,766,000	26,814,000	23,260,000	21,931,000	26,562,000	318,600,372
System Billing Demand - KW			61,724	57,422	51,596	43,946	50,754	64,184	63,000	63,000	55,000	49,000	46,000	58,000	664,628
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	
Demand and Non-Fuel:															
Demand Charge - $/KW			6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	
Customer Charge - $			550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,979	31,980	31,980	31,980	31,980	31,980	31,980	
Purchased Power Costs:															
Base Fuel Costs			633,716	569,661	485,566	483,638	610,171	667,587	675,070	670,738	584,570	507,085	478,083	579,756	6,945,641
Subtotal Fuel Costs			633,716	569,661	485,566	483,638	610,171	667,587	675,070	670,738	584,570	507,085	478,083	579,756	6,945,641
Demand and Non-Fuel Costs:															
Demand Charge			419,724	390,489	350,852	298,847	345,128	436,452	428,404	428,404	380,794	333,194	312,804	394,394	4,519,456
Customer Charge			550	550	550	550	550	550	550	550	550	550	550	550	6,600
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,979	31,980	31,980	31,980	31,980	31,980	31,980	383,756
Subtotal Demand & Non-Fuel Costs			452,253	422,999	383,382	331,376	377,657	468,981	460,934	460,934	413,324	365,724	345,334	426,924	4,909,822
Total System Purchased Power Costs			1,085,969	992,660	868,948	815,014	987,828	1,136,568	1,136,004	1,131,672	997,894	872,809	823,417	1,006,680	11,855,463
Sales Revenues															
Fuel Adjustment Revenues:		Rates													
Residential	RS	0.04053	610,329	537,156	448,887	373,857	378,106	515,784	474,965	475,255	475,545	475,787	476,077	476,318	5,717,865
Commercial	GS	0.04002	98,051	94,828	88,721	85,568	85,809	107,279	94,025	94,025	94,025	94,025	94,025	94,025	1,124,006
Commercial	GSD	0.03735	256,884	246,498	240,028	238,087	247,797	305,590	287,131	287,131	287,131	287,131	287,131	287,131	3,257,670
Industrial	GSLD	0.03533	145,277	112,052	109,904	116,361	119,848	141,784	109,561	109,561	109,561	109,561	109,561	109,561	1,402,570
Residential	OL,OL-2	0.02910	5,511	5,863	5,873	6,718	8,826	8,871	8,294	7,635	8,189	8,170	8,120	8,184	92,254
Other	SL-1,SL-2,SL-3	0.02901	5,647	5,663	5,608	2,656	2,850	2,896	2,342	2,346	2,345	2,350	1,788	2,342	38,832
Total Fuel Revenues			1,121,899	1,001,859	899,021	825,047	843,034	1,062,184	976,318	975,953	976,797	977,024	976,700	977,561	11,633,197
Non-Fuel Revenues			615,552	570,324	528,974	520,469	571,446	684,133	629,032	626,437	629,153	629,106	626,480	629,579	7,240,705
Total Sales Revenue			1,737,251	1,572,183	1,427,995	1,345,536	1,414,480	1,746,317	1,605,350	1,602,390	1,605,950	1,606,130	1,603,180	1,607,140	18,873,902
KWH Sales:															
Residential	RS		15,058,887	13,253,812	11,075,172	9,219,086	9,330,391	12,727,271	11,718,839	11,725,997	11,733,155	11,739,120	11,746,278	11,752,243	141,080,251
Commercial	GS		2,449,978	2,364,449	2,216,834	2,138,020	2,139,062	2,680,553	2,349,450	2,349,450	2,349,450	2,349,450	2,349,450	2,349,450	28,086,596
Commercial	GSD		6,881,983	6,599,136	6,425,905	6,373,964	6,633,909	8,181,110	7,687,564	7,687,564	7,687,564	7,687,564	7,687,564	7,687,564	87,221,390
Industrial	GSLD		4,142,568	3,171,164	3,110,384	3,293,135	3,391,744	4,012,052	3,101,065	3,101,065	3,101,065	3,101,065	3,101,065	3,101,065	39,727,438
Residential	OL,OL-2		188,765	201,512	201,849	299,848	303,598	305,136	285,005	262,386	281,418	280,747	279,031	281,222	3,170,519
Other	SL-1,SL-2,SL-3		194,675	195,175	193,306	91,570	98,243	99,829	80,730	80,867	80,881	80,995	81,576	80,738	1,338,585
Total KWH Sales			28,916,856	25,785,248	23,223,450	21,415,624	21,896,946	28,005,951	25,222,653	25,207,331	25,233,533	25,238,941	25,224,964	25,252,262	300,623,779
True-up Calculation:															Period to Date
Fuel Revenues			1,121,899	1,001,859	899,021	825,047	843,034	1,062,184	976,318	975,953	976,797	977,024	976,700	977,561	11,633,197
True-up Provision		DIVIDED BY 12	52,022	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	624,352
Gross Receipts Tax Refund			0	0				0	0	0	0	0	0	0	0
Fuel Revenue			1,069,877	949,829	846,991	773,017	791,004	1,030,154	924,288	923,923	924,767	924,994	924,670	925,531	11,008,845
Total Purchased Power Costs			1,085,969	992,660	868,948	815,014	987,828	1,136,568	1,136,004	1,131,672	997,894	872,809	823,417	1,006,680	11,855,463
True-up Provision for the Period			(16,292)	(42,831)	(21,957)	(41,997)	(196,824)	(106,414)	(211,716)	(207,749)	(73,127)	52,185	101,253	(81,149)	(846,618)
Interest Provision for the Period			(528)	(490)	(462)	(457)	(530)	(705)	(757)	(903)	(985)	(947)	(830)	(773)	(8,357)
True-up and Interest Provision Beginning of Period			(624,352)	(589,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,058,732)	(1,080,814)	(977,546)	(825,093)	(624,352)
True-up Collected or (Refunded)			52,022	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	624,352
End of Period, Net True-up			(589,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,056,732)	(1,080,814)	(977,546)	(825,093)	(854,985)	(854,985)
10% Rule															
Interest Provision:															-7.21%
Beginning True-up Amount			(624,352)	(589,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,058,732)	(1,080,814)	(977,546)	(825,093)	
Ending True-up Amount Before Interest			(588,622)	(579,951)	(550,368)	(540,797)	(686,048)	(740,962)	(901,353)	(1,057,829)	(1,079,829)	(976,599)	(824,263)	(854,212)	
Total Beginning and Ending True-up			(1,212,974)	(1,169,101)	(1,130,809)	(1,091,627)	(1,227,302)	(1,427,540)	(1,643,020)	(1,959,939)	(2,138,561)	(2,057,413)	(1,801,809)	(1,679,305)	
Average True-up Amount			(606,487)	(584,551)	(565,405)	(545,814)	(613,651)	(713,770)	(821,510)	(979,970)	(1,069,281)	(1,028,707)	(900,905)	(839,653)	
Average Annual Interest Rate			1.0450%	1.0050%	0.9800%	1.0050%	1.0350%	1.1850%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	
Monthly Average Interest Rate			0.0871%	0.0838%	0.0817%	0.0838%	0.0863%	0.0988%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	
Interest Provision			(528)	(490)	(462)	(457)	(530)	(705)	(757)	(903)	(985)	(947)	(830)	(773)	

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Florida Public Utilities Company
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FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

SCHEDULE E1-B1

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	6,945,641	6,758,252	187,389	2.8%	318,600	310,000	8,600	2.8%	2.18005	2.18008	(0.00003)	0.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	4,909,822	4,755,958	153,864	3.2%	318,600	310,000	8,600	2.8%	1.54108	1.53418	0.00688	0.5%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	11,855,463	11,514,210	341,253	3.0%	318,600	310,000	8,600	2.8%	3.72111	3.71426	0.00685	0.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					318,600	310,000	8,600	2.8%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Fuel Cost of Other Power Sales (A6)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	11,855,463	11,514,210	341,253	3.0%	318,600	310,000	8,600	2.8%	3.72111	3.71426	0.00685	0.2%
21	Net Unbilled Sales	184,307 *	(469,854) *	654,161	-139.2%	4,953	(12,650)	17,603	-139.2%	0.06131	(0.15157)	0.21288	-140.5%
22	Company Use	10,419 *	9,286 *	1,133	12.2%	280	250	30	12.0%	0.00347	0.00300	0.00047	15.7%
23	T & D Losses	474,218 *	460,568 *	13,650	3.0%	12,744	12,400	344	2.8%	0.15775	0.14857	0.00918	6.2%
24	SYSTEM KWH SALES	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
28	GPIF**												
29	TRUE-UP**	624,352	343,777	280,575	81.6%	300,623	310,000	(9,377)	-3.0%	0.20769	0.11090	0.09679	87.3%
30	TOTAL JURISDICTIONAL FUEL COST	12,479,815	11,857,987	621,828	5.2%	300,623	310,000	(9,377)	-3.0%	4.15132	3.82516	0.32616	8.5%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									4.15431	3.82791	0.32640	8.5%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									4.154	3.828	0.326	8.5%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003.)(Estimated)	$	(69,844)

Exhibit No._____
DOCKET NO. 040001-EI
Florida Public Utilities Company
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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

Schedule E1-B

FERNANDINA BEACH		ACTUAL JANUARY 2004	ACTUAL FEBRUARY 2004	ACTUAL MARCH 2004	ACTUAL APRIL 2004	ACTUAL MAY 2004	ACTUAL JUNE 2004	Estimated JULY 2004	Estimated AUGUST 2004	Estimated SEPTEMBER 2004	Estimated OCTOBER 2004	Estimated NOVEMBER 2004	Estimated DECEMBER 2004	Total Estimated
Total System Sales - KWH		37,283,836	35,256,592	36,663,661	31,559,370	31,625,808	43,185,305	37,426,921	38,221,164	38,696,444	38,738,044	38,779,644	39,342,084	446,808,851
JSC Purchases - KWH		534,500	607,800	271,200	308,900	308,700	165,700	400,000	400,000	400,000	400,000	400,000	400,000	4,595,800
JEA Purchases - KWH		38,227,951	34,757,822	37,145,830	31,767,791	35,767,009	48,313,294	37,026,921	37,821,164	38,296,444	38,338,044	38,379,644	38,942,084	454,783,978
System Billing Demand - KW		83,373	88,032	89,261	58,509	71,501	85,210	93,373	93,117	92,000	78,108	67,850	83,387	963,719
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01786	0.01786	0.01786	0.01788	0.01786	0.01786	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:														
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH		0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	
Purchased Power Costs:														
CCA Fuel Costs		9,995	11,366	5,071	5,795	5,736	3,098	7,480	7,480	7,480	7,480	7,480	7,480	85,941
JEA Base Fuel Costs		682,751	620,775	663,425	567,373	638,799	862,875	683,147	697,800	706,589	707,337	708,104	718,481	8,257,436
JEA Fuel Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Fuel Costs		692,746	632,141	668,496	573,168	644,534	865,974	690,627	705,280	714,049	714,817	715,584	725,961	8,343,377
Demand and Non-Fuel Costs:														
Demand Charge		500,236	528,191	415,586	351,054	429,006	511,260	560,237	558,701					
Customer Charge		225	225	225	225	225	225	225	225	225	225	225	225	
Energy Charge		62,694	57,003	60,919	52,099	58,658	79,234	38,878	39,712	40,211	40,255	40,299	40,889	610,851
Subtotal Demand & Non-Fuel Costs		563,157	585,419	476,710	403,378	487,889	590,719	599,339	598,638	592,435	509,115	447,623	641,436	8,395,857
Total System Purchased Power Costs		1,255,903	1,217,560	1,145,206	976,546	1,132,423	1,456,693	1,289,966	1,303,918	1,306,484	1,223,932	1,163,207	1,367,396	14,739,234
Less Direct Billing To GSLD Class:														
Demand		32,386	100,131	38,072	66,256	31,397	0	132,870	132,870	132,870	132,870	132,870	132,870	1,065,462
Commodity		169,273	168,076	219,070	155,408	163,672	220,338	212,079	212,079	212,079	212,079	212,079	212,079	2,368,311
Net Purchased Power Costs		1,054,244	949,353	888,064	754,882	937,354	1,236,355	945,017	958,969	961,535	878,983	818,258	922,447	11,305,481
Sales Revenues														
Fuel Adjustment Revenues:	Rate													
RS	0.02942	503,570	481,474	454,013	367,255	367,254	552,193	485,372	488,295	489,510	490,725	491,940	508,369	5,579,970
GS	0.02915	82,422	68,936	58,493	68,789	61,743	83,633	79,935	80,481	93,036	93,036	93,036	93,036	956,576
GSD	0.02739	235,097	213,094	221,263	243,855	238,670	285,531	198,334	215,172	215,172	215,172	215,172	215,172	2,711,704
OL	0.01931	1,072	1,182	1,252	2,987	3,093	1,975	1,697	1,913	1,913	1,913	1,913	1,913	22,823
SL,CSL	0.01931	2,044	1,620	1,951	159	0	1,426	1,319	2,002	2,002	2,002	2,002	2,002	18,829
Total Fuel Revenues (Excl. GSLD1)		824,205	766,606	736,972	683,045	670,760	924,758	766,657	787,863	801,633	802,848	804,063	820,492	9,389,902
GSLD1 Fuel Revenues		201,659	268,207	257,142	221,664	195,069	220,338	344,949	344,949	344,949	344,949	344,949	344,949	3,433,773
Non-Fuel Revenues		628,719	615,792	602,002	573,304	614,252	738,533	622,094	642,888	656,918	658,203	659,786	675,159	7,887,852
Total Sales Revenue		1,654,583	1,650,605	1,596,116	1,478,013	1,480,081	1,883,629	1,733,700	1,775,700	1,803,500	1,806,000	1,808,800	1,840,600	20,511,327
KWH Sales:														
RS		17,247,852	16,493,031	16,540,957	12,437,090	12,483,677	18,770,046	16,616,650	15,716,700	16,758,300	16,799,900	16,841,500	17,403,920	194,109,623
GS		2,854,104	2,381,385	2,020,654	2,348,407	2,118,178	2,899,144	2,815,997	2,834,874	3,268,554	3,268,554	3,268,554	3,268,554	33,318,959
GSD		8,623,382	7,851,281	8,108,654	8,671,367	8,713,680	10,424,519	8,787,568	9,406,190	9,406,190	9,406,190	9,406,190	9,406,190	108,411,381
GSLD1		8,430,000	8,370,000	10,910,000	7,740,000	8,150,000	10,970,000	9,050,000	9,060,000	9,060,000	9,060,000	9,060,000	9,060,000	106,920,000
OL		56,808	61,158	64,995	154,401	160,271	102,331	88,164	99,400	99,400	99,400	99,400	99,400	1,184,128
SL,CSL		106,195	99,737	101,357	6,105	0	49,265	68,542	104,000	104,000	104,000	104,000	104,000	953,181
Total KWH Sales		37,317,311	35,256,592	36,746,617	31,558,370	31,625,806	43,185,305	37,426,921	38,221,164	38,696,444	38,738,044	38,779,644	39,342,064	446,895,282
True-up Calculation (Excl. GSLD):														
Fuel Revenues		824,205	766,606	736,972	683,045	670,760	924,758	766,657	787,863	801,633	802,848	804,063	820,492	9,389,902
True-up Provision		(153,169)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(1,837,973)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		977,374	919,770	890,136	836,209	823,924	1,077,922	919,821	941,027	954,797	956,012	957,227	973,656	11,227,875
Net Purchased Power Costs		1,054,244	949,353	888,064	754,882	937,354	1,236,355	945,017	958,969	961,535	878,983	818,258	922,447	11,305,481
True-up Provision for the Period		(76,870)	(29,583)	2,072	81,327	(113,430)	(158,433)	(25,196)	(17,942)	(6,738)	77,029	138,969	51,209	(77,586)
Interest Provision for the Period		1,501	1,272	1,105	1,041	927	776	499	338	186	78	36	(17)	7,742
True-up and Interest Provision														
Beginning of Period		1,837,973	1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	1,837,973
True-up Collected or (Refunded)		(153,169)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(1,837,973)
End of Period, Net True-up		1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	(69,844)	(69,844)
10% Rule Interest Provision:														-0.474
Beginning True-up Amount		1,837,973	1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	
Ending True-up Amount Before Interest		1,607,934	1,426,688	1,276,868	1,206,136	940,583	629,913	452,329	281,722	122,158	46,209	32,092	(69,827)	
Total Beginning and Ending True-up		3,445,907	3,036,123	2,704,828	2,484,109	2,147,760	1,571,423	1,083,018	734,550	404,218	168,553	78,379	(37,699)	
Average True-up Amount		1,722,954	1,518,062	1,352,414	1,242,055	1,073,880	785,712	541,509	367,275	202,109	84,277	39,190	(18,850)	
Average Interest Rate		1.0450%	1.0050%	0.9800%	1.0050%	1.0350%	1.1850%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	
Monthly Average Interest Rate		0.0871%	0.0838%	0.0817%	0.0838%	0.0863%	0.0988%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	
Interest Provision		1,501	1,272	1,105	1,041	927	776	499	338	186	78	36	(17)	

Exhibit No.
DOCKET NO. 040001-EI
Florida Public Utilities Company
(GMB-1)
Page 5 of 6

SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2004 - DECEMBER 2004

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	8,257,436	8,514,672	(257,236)	-3.0%	454,784	461,500	(6,716)	-1.5%	1.81568	1.84500	(0.02932)	-1.6%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	6,395,857	6,533,715	(137,858)	-2.1%	454,784	461,500	(6,716)	-1.5%	1.40635	1.41576	(0.00941)	-0.7%
11 Energy Payments to Qualifying Facilities (A8a)	85,941	89,760	(3,819)	-4.3%	4,596	4,800	(204)	-4.3%	1.86991	1.87000	(0.00009)	0.0%
12 TOTAL COST OF PURCHASED POWER	14,739,234	15,138,147	(398,913)	-2.6%	459,380	466,300	(6,920)	-1.5%	3.20851	3.24644	(0.03793)	-1.2%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					459,380	466,300	(6,920)	-1.5%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)												
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,739,234	15,138,147	(398,913)	-2.6%	459,380	466,300	(6,920)	-1.5%	3.20851	3.24644	(0.03793)	-1.2%
21 Net Unbilled Sales (A4)	(497,127) *	(922,443) *	425,316	-46.1%	(15,494)	(28,414)	12,920	-45.5%	(0.11126)	(0.19782)	0.08656	-43.8%
22 Company Use (A4)	16,107 *	14,154 *	1,953	13.8%	502	436	66	15.1%	0.00360	0.00304	0.00056	18.4%
23 T & D Losses (A4)	884,362 *	908,289 *	(23,927)	-2.6%	27,563	27,978	(415)	-1.5%	0.19793	0.19479	0.00314	1.6%
24 SYSTEM KWH SALES	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
28 GPIF**												
29 TRUE-UP**	(1,837,973)	(1,302,700)	(535,273)	41.1%	446,809	466,300	(19,491)	-4.2%	(0.41136)	(0.27937)	(0.13199)	47.3%
30 TOTAL JURISDICTIONAL FUEL COST	12,901,261	13,835,447	(934,186)	-6.8%	446,809	466,300	(19,491)	-4.2%	2.88742	2.96707	(0.07965)	-2.7%
31 Revenue Tax Factor									1.01597	1.01597	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									2.93353	3.01445	(0.08092)	-2.7%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)												

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

ORIGINAL

LAW OFFICES
Messer, Caparello & Self
A Professional Association

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Tallahassee, Florida 32302-1876
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November 2, 2004

BY HAND DELIVERY
Ms. Blanca Bayo, Director
Division of Records and Reporting
Room 110, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Florida Public Utilities Company; Docket No. 040001-EI

Dear Ms. Bayo:

Enclosed for filing on behalf of Florida Public Utilities Company in this docket is an original and 10 copies of Revised Composite Exhibit GMB-2. This exhibit will replace the Composite Exhibit GMB-2 filed on September 17, 2004

Please acknowledge receipt of these documents by stamping the enclosed extra copy of this letter.

CMP ____
COM 5
CTR mg
ECR ____
GCL ____
OPC ____
MMS ____
RCA ____
SCR ____
SEC 1
OTH ____

Thank you for your assistance.

Sincerely,

Norman H. Horton, Jr.

NHH/amb
Enclosures
cc: Mr. George Bachman

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 22
COMPANY/ FPUC
WITNESS. George M. Bachman (GMB-2)
DATE 11-08-04

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DOCUMENT NUMBER-DA
11806 NOV-2
FPSC-COMMISSION CLER

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

SCHEDULE E1
PAGE 1 OF 2

MARIANNA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	7,536,301		336,442	2.24000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	5,219,208		336,442	1.55130
10a	Demand Costs of Purchased Power	4,828,860	*		
10b	Transformation Energy & Customer Costs of Purchased Power	390,348	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	12,755,509		336,442	3.79130
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	12,755,509		336,442	3.79130
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	12,755,509		336,442	3.79130
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	9,478	*	250	0.00301
23	T & D Losses	805,234	*	21,239	0.25567
24	SYSTEM MWH SALES	12,755,509		314,953	4.04997
25	Less Total Demand Cost Recovery	4,828,860	***		
26	Jurisdictional MWH Sales	7,926,649		314,953	2.51677
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	7,926,649		314,953	2.51677
28	GPIF **				
29	TRUE-UP **	511,209		314,953	0.16231
30	TOTAL JURISDICTIONAL FUEL COST	8,437,858		314,953	2.67908
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				2.68101
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH				2.681

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 1 OF 14
REVISED

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

MARIANNA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	149,152,998	61.971%	54,950.2	1.089	1.000	59,840.8	149,152,998	52.06%	47.35%
35	GS	29,469,134	64.200%	10,479.9	1.089	1.000	11,412.6	29,469,134	9.93%	9.36%
36	GSD	105,180,585	73.168%	32,820.1	1.083	1.000	35,544.2	105,180,585	30.93%	33.40%
37	GSLD	26,117,895	84.178%	7,083.8	1.038	1.000	7,353.0	26,117,895	6.40%	8.29%
38	OL, OL1	3,805,245	160.732%	540.5	1.089	1.000	588.6	3,805,245	0.51%	1.21%
39	SL1, SL2 & SL3	1,228,307	160.732%	174.5	1.089	1.000	190.0	1,228,307	0.17%	0.39%
40	TOTAL	314,954,164		106,049.0			114,929.2	314,954,164	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) ot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	emand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	48.05%	3.64%	51.69%	$2,496,038	0.01673	0.01674	0.02681	$0.04355
42	GS	9.17%	0.72%	9.89%	477,574	0.01621	0.01622	0.02681	$0.04303
43	GSD	28.55%	2.57%	31.12%	1,502,741	0.01429	0.01430	0.02681	$0.04111
44	GSLD	5.91%	0.64%	6.55%	316,290	0.01211	0.01212	0.02681	$0.03893
45	OL, OL1	0.47%	0.09%	0.56%	27,042	0.00711	0.00712	0.02681	$0.03393
46	SL1, SL2 & SL3	0.16%	0.03%	0.19%	9,175	0.00747	0.00748	0.02681	$0.03429
47	TOTAL	92.31%	7.69%	100.00%	$4,828,860				

(2) From Gulf Power Co. 2003 Load Research results.
(4) From Fernandina Rate Case.

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SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2004)(Estimated)	$	(511,209)
Estimated kilowatt hour sales for the months of January 2005 - December 2005 as per estimate filed with the Commission.		314,954,164
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2005 - December 2005.		(0.16231)

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

LINE NO.			(a) 2005 JANUARY	(b) 2005 FEBRUARY	(c) ESTIMATED 2005 MARCH	(d) 2005 APRIL	(e) 2005 MAY	2005 JUNE	2005 JULY	2005 AUGUST	2005 SEPTEMBER	2005 OCTOBER	2005 NOVEMBER	(f) 2005 DECEMBER	(g) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		676,614	521,942	535,360	534,621	640,954	682,349	741,910	749,347	668,954	581,930	543,581	658,739	7,536,301	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		516,249	427,289	372,384	359,874	432,154	464,124	494,704	473,854	446,749	396,709	377,249	457,869	5,219,208	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,192,863	949,231	907,744	894,495	1,073,108	1,146,473	1,236,614	1,223,201	1,115,703	978,639	920,830	1,116,608	12,755,509	5
6	LESS: TOTAL DEMAND COST RECOVERY		483,720	394,760	339,855	327,345	399,625	431,595	462,175	441,325	414,220	364,180	344,720	425,340	4,828,860	6
7	TOTAL OTHER COST TO BE RECOVERED		709,143	554,471	567,889	567,150	673,483	714,878	774,439	781,876	701,483	614,459	576,110	691,268	7,926,649	7
7a	SYSTEM KWH SOLD (MWH)		29,693	25,478	21,442	20,730	24,500	27,886	28,978	29,325	31,065	25,501	22,559	27,796	314,953	7a
7b	COST PER KWH SOLD (CENTS/KWH)		2.38825	2.17627	2.64849	2.73589	2.74891	2.56357	2.67251	2.66624	2.25811	2.40955	2.55379	2.48693	2.51677	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		2.38825	2.17627	2.64849	2.73589	2.74891	2.56357	2.67251	2.66624	2.25811	2.40955	2.55379	2.48693	2.51677	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	11
12	TOTAL		2.55056	2.33858	2.81080	2.89820	2.91122	2.72588	2.83482	2.82855	2.42042	2.57186	2.71610	2.64924	2.67908	12
13	REVENUE TAX FACTOR	0.00072	0.00184	0.00168	0.00202	0.00209	0.00210	0.00196	0.00204	0.00204	0.00174	0.00185	0.00196	0.00191	0.00193	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.55240	2.34026	2.81282	2.90029	2.91332	2.72784	2.83686	2.83059	2.42216	2.57371	2.71806	2.65115	2.68101	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.552	2.340	2.813	2.900	2.913	2.728	2.837	2.831	2.422	2.574	2.718	2.651	2.681	15

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2005	GULF POWER COMPANY	RE	30,206,000			30,206,000	2.239999	3.949093	676,614
FEBRUARY	2005	GULF POWER COMPANY	RE	23,301,000			23,301,000	2.239998	4.073778	521,942
MARCH	2005	GULF POWER COMPANY	RE	23,900,000			23,900,000	2.240001	3.798092	535,360
APRIL	2005	GULF POWER COMPANY	RE	23,867,000			23,867,000	2.240001	3.747832	534,621
MAY	2005	GULF POWER COMPANY	RE	28,614,000			28,614,000	2.240000	3.750290	640,954
JUNE	2005	GULF POWER COMPANY	RE	30,462,000			30,462,000	2.240000	3.763617	682,349
JULY	2005	GULF POWER COMPANY	RE	33,121,000			33,121,000	2.240000	3.733625	741,910
AUGUST	2005	GULF POWER COMPANY	RE	33,453,000			33,453,000	2.240000	3.656476	749,347
SEPTEMBER	2005	GULF POWER COMPANY	RE	29,864,000			29,864,000	2.240001	3.735946	668,954
OCTOBER	2005	GULF POWER COMPANY	RE	25,979,000			25,979,000	2.240000	3.767039	581,930
NOVEMBER	2005	GULF POWER COMPANY	RE	24,267,000			24,267,000	2.239999	3.794577	543,581
DECEMBER	2005	GULF POWER COMPANY	RE	29,408,000			29,408,000	2.239997	3.796953	658,739
TOTAL				336,442,000	0	0	336,442,000	2.240000	3.791295	7,536,301

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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

	JANUARY 2005	FEBRUARY 2005	MARCH 2005	APRIL 2005	MAY 2005	JUNE 2005	JULY 2005
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	24.26	24.26
FUEL RECOVERY FACTOR CENTS/KWH	4.36	4.36	4.36	4.36	4.36	4.36	4.36
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	43.55	43.55	43.55	43.55	43.55	43.55	43.55
GROSS RECEIPTS TAX	1.74	1.74	1.74	1.74	1.74	1.74	1.74
TOTAL REVENUES *** $	69.55	69.55	69.55	69.55	69.55	69.55	69.55

	AUGUST 2005	SEPTEMBER 2005	OCTOBER 2005	NOVEMBER 2005	DECEMBER 2005	PERIOD TOTAL
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	291.12
FUEL RECOVERY FACTOR CENTS/KWH	4.36	4.36	4.36	4.36	4.36	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	43.55	43.55	43.55	43.55	43.55	522.60
GROSS RECEIPTS TAX	1.74	1.74	1.74	1.74	1.74	20.88
TOTAL REVENUES *** $	69.55	69.55	69.55	69.55	69.55	834.60

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	10.00
CENTS/KWH	13.73
CONSERVATION FACTOR	0.530
	24.26

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

FERNANDINA BEACH DIVISON

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)				
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	8,687,929		470,890	1.84500
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Non Fuel Cost of Purch Power (E2)	6,396,947		470,890	1.35848
10a	Demand Costs of Purchased Power	5,899,812	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	497,135	*		
11	Energy Payments to Qualifying Facilities (E8a)	56,056		2,998	1.86978
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	15,140,932		473,888	3.19504
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	15,140,932		473,888	3.19504
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	15,140,932		473,888	3.19504
21	Net Unbilled Sales	0	*	(0)	0.00000
22	Company Use	13,930	*	436	0.00294
23	T & D Losses	(13,930)	*	(436)	-0.00294
24	SYSTEM MWH SALES	15,140,932		473,888	3.19504
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	15,140,932		473,888	3.19504
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	15,140,932		473,888	3.19504
27a	GSLD1 MWH Sales			126,705	
27b	Other Classes MWH Sales			347,183	
27c	GSLD1 CP KW			258,000	*
28	GPIF **				
29	TRUE-UP (OVER) UNDER RECOVERY **	1,372,544		473,888	0.28963
30	TOTAL JURISDICTIONAL FUEL COST	16,513,476		473,888	3.48468
30a	Demand Purchased Power Costs (Line 10a)	5,899,812	*		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	9,241,120	*		
30c	True up Over/Under Recovery (Line 29)	1,372,544	*		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	5,899,812		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $6.18)	1,594,440	258,000 (KW)	$6.18 /KW
33	Balance to Other Classes	4,305,372	347,183	1.24009
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	9,241,120		
35	Total KWH Purchased (Line 12)		473,888	
36	Average Cost per KWH Purchased			1.95006
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			2.00856
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	2,544,945	126,705	2.00856
39	Balance to Other Classes	6,696,175	347,183	1.92871
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,594,440	258,000 (KW)	$6.18 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.18 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	2,544,945	126,705	2.00856
40e	Total Non-demand Costs Including True-up	2,544,945	126,705	2.00856
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			2.01001
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	11,001,547	347,183	3.16880
41b	Less: Total Demand Cost Recovery	4,305,372 ***		
41c	Total Other Costs to be Recovered	6,696,175	347,183	1.92871
41d	Other Classes' Portion of True-up (Line 30c)	1,372,544	347,183	0.39534
41e	Total Demand & Non-demand Costs Including True-up	8,068,719	347,183	2.32405
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			2.326

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

FERNANDINA BEACH DIVISON

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	204,266,826	63.060%	73,955.4	1.089	1.000	80,537.4	204,266,826	62.67%	57.70%
45	GS	32,015,259	69.973%	10,446.1	1.089	1.000	11,375.8	32,015,259	8.85%	9.04%
46	GSD	104,244,617	77.702%	30,630.0	1.083	1.000	33,172.3	104,244,617	25.81%	29.45%
47	GSLD	11,350,703	83.923%	3,087.9	1.083	1.000	3,344.2	11,350,703	2.60%	3.21%
48	OL	1,281,755	565.360%	51.8	1.089	1.000	56.4	1,281,755	0.04%	0.36%
49	SL	834,724	565.360%	33.7	1.089	1.000	36.7	834,724	0.03%	0.24%
	TOTAL	353,993,884		118,204.9			128,522.8	353,993,884	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	57.83%	4.44%	62.27%	$2,680,955	0.01312	0.01313	0.02326	0.03639
51	GS	8.17%	0.70%	8.87%	381,886	0.01193	0.01194	0.02326	0.03520
52	GSD	23.82%	2.27%	26.09%	1,123,272	0.01078	0.01079	0.02326	0.03405
53	GSLD	2.40%	0.25%	2.65%	114,092	0.01005	0.01006	0.02326	0.03332
54	OL	0.04%	0.03%	0.07%	3,014	0.00235	0.00235	0.02326	0.02561
55	SL	0.03%	0.02%	0.05%	2,153	0.00258	0.00258	0.02326	0.02584
	TOTAL	92.29%	7.71%	100.00%	$4,305,372				

(2) From Florida Power & Light Co. 2003 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2005 - DECEMBER 2005
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2004.)(Estimated)	$	(1,372,544)
Estimated kilowatt hour sales for the months of January 2005 - December 2005 as per estimate filed with the Commission. (Excludes GSLD1 customers)		353,993,884
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2005 - December 2005.		-0.38773

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH DIVISION

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		713,006	678,712	641,283	582,428	659,708	891,980	877,384	912,469	809,151	638,140	514,118	769,550	8,687,929	3
3a	DEMAND & NON FUEL COST OF PUR POWER		552,872	559,620	555,858	405,958	466,774	562,391	706,874	715,555	532,843	440,593	406,187	491,422	6,396,947	3a
3b	QUALIFYING FACILITIES		3,099	4,392	2,917	6,468	2,508	5,732	6,865	4,393	5,071	4,600	3,545	6,466	56,056	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,268,977	1,242,724	1,200,058	994,854	1,128,990	1,460,103	1,591,123	1,632,417	1,347,065	1,083,333	923,850	1,267,438	15,140,932	5
5a	LESS: TOTAL DEMAND COST RECOVERY		376,964	375,680	332,888	289,754	342,788	410,840	415,148	413,612	406,910	323,546	262,010	355,232	4,305,372	5a
5b	TOTAL OTHER COST TO BE RECOVERED		892,013	867,044	867,170	705,100	786,202	1,049,263	1,175,975	1,218,805	940,155	759,787	661,840	912,206	10,835,560	5b
6	APPORTIONMENT TO GSLD CLASS		344,946	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	4,139,385	6
6a	BALANCE TO OTHER CLASSES		547,067	522,095	522,221	360,151	441,253	704,314	831,026	873,856	595,206	414,838	316,891	567,257	6,696,175	6a
6b	SYSTEM KWH SOLD (MWH)		38,811	37,021	34,914	31,914	35,891	48,652	47,922	49,691	44,128	34,834	28,055	42,056	473,888	6b
7	GSLD MWH SOLD		10,559	10,559	10,560	10,559	10,559	10,560	10,551	10,559	10,559	10,562	10,559	10,559	126,705	7
7a	BALANCE MWH SOLD OTHER CLASSES		28,252	26,462	24,354	21,355	25,332	38,092	37,371	39,132	33,569	24,272	17,496	31,497	347,183	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		1.93638	1.97297	2.1443	1.68651	1.7419	1.84897	2.22373	2.23308	1.7731	1.70915	1.81121	1.80099	1.92871	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		1.93638	1.97297	2.14430	1.68651	1.74190	1.84897	2.22373	2.23308	1.77310	1.70915	1.81121	1.80099	1.92871	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	1,372,544	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	11
12	TOTAL		2.33172	2.36831	2.53964	2.08185	2.13724	2.24431	2.61907	2.62842	2.16844	2.10449	2.20655	2.19633	2.32405	12
13	REVENUE TAX FACTOR	0.00072	0.00168	0.00171	0.00183	0.00150	0.00154	0.00162	0.00189	0.00189	0.00156	0.00152	0.00159	0.00158	0.00167	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.33340	2.37002	2.54147	2.08335	2.13878	2.24593	2.62096	2.63031	2.17000	2.10601	2.20814	2.19791	2.32572	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.333	2.37	2.541	2.083	2.139	2.246	2.621	2.63	2.17	2.106	2.208	2.198	2.326	15

EXHIBIT NO. _____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 11 OF 14

REVISED

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,645,324			38,645,324	1.844999	3.275630	713,006
FEBRUARY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,786,543			36,786,543	1.845001	3.366264	678,712
MARCH 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,757,897			34,757,897	1.844999	3.444227	641,283
APRIL 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,567,895			31,567,895	1.845001	3.130985	582,428
MAY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,756,543			35,756,543	1.844999	3.150422	659,708
JUNE 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	48,345,789			48,345,789	1.845000	3.008268	891,980
JULY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	47,554,698			47,554,698	1.845000	3.331444	877,384
AUGUST 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	49,456,290			49,456,290	1.845001	3.291844	912,469
SEPTEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	43,856,398			43,856,398	1.845001	3.059973	809,151
OCTOBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,587,543			34,587,543	1.845000	3.118848	638,140
NOVEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	27,865,498			27,865,498	1.844998	3.302668	514,118
DECEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	41,710,045			41,710,045	1.844999	3.023185	769,550
TOTAL			470,890,463	0	0	470,890,463	1.845000	3.203479	8,687,929

EXHIBIT NO. _____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 12 OF 14
REVISED

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2005	JEFFERSON SMURFIT CORPORATION		165,700			165,700	1.870247	1.870247	3,099
FEBRUARY 2005	JEFFERSON SMURFIT CORPORATION		234,888			234,888	1.869827	1.869827	4,392
MARCH 2005	JEFFERSON SMURFIT CORPORATION		156,000			156,000	1.869872	1.869872	2,917
APRIL 2005	JEFFERSON SMURFIT CORPORATION		345,876			345,876	1.870034	1.870034	6,468
MAY 2005	JEFFERSON SMURFIT CORPORATION		134,098			134,098	1.870274	1.870274	2,508
JUNE 2005	JEFFERSON SMURFIT CORPORATION		306,500			306,500	1.870147	1.870147	5,732
JULY 2005	JEFFERSON SMURFIT CORPORATION		367,098			367,098	1.870073	1.870073	6,865
AUGUST 2005	JEFFERSON SMURFIT CORPORATION		234,945			234,945	1.869799	1.869799	4,393
SEPTEMBER 2005	JEFFERSON SMURFIT CORPORATION		271,200			271,200	1.869838	1.869838	5,071
OCTOBER 2005	JEFFERSON SMURFIT CORPORATION		245,987			245,987	1.870018	1.870018	4,600
NOVEMBER 2005	JEFFERSON SMURFIT CORPORATION		189,564			189,564	1.870081	1.870081	3,545
DECEMBER 2005	JEFFERSON SMURFIT CORPORATION		345,765			345,765	1.870056	1.870056	6,466
TOTAL			2,997,621	0	0	2,997,621	1.870016	1.870016	56,056

EXHIBIT NO. _____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
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REVISED

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	JANUARY 2005	FEBRUARY 2005	MARCH 2005	APRIL 2005	MAY 2005	JUNE 2005	JULY 2005
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	24.26	24.26
FUEL RECOVERY FACTOR CENTS/KWH	3.64	3.64	3.64	3.64	3.64	3.64	3.64
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	36.39	36.39	36.39	36.39	36.39	36.39	36.39
GROSS RECEIPTS TAX	0.62	0.62	0.62	0.62	0.62	0.62	0.62
TOTAL REVENUES *** $	61.27	61.27	61.27	61.27	61.27	61.27	61.27

	AUGUST 2005	SEPTEMBER 2005	OCTOBER 2005	NOVEMBER 2005	DECEMBER 2005	PERIOD TOTAL
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	291.12
FUEL RECOVERY FACTOR CENTS/KWH	3.64	3.64	3.64	3.64	3.64	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	36.39	36.39	36.39	36.39	36.39	436.68
GROSS RECEIPTS TAX	0.62	0.62	0.62	0.62	0.62	7.44
TOTAL REVENUES *** $	61.27	61.27	61.27	61.27	61.27	735.24

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	10.00
CENTS/KWH	13.73
CONSERVATION FACTOR	0.530
	24.26

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 14 OF 14

REVISED

GULF POWER COMPANY
COAL SUPPLIERS
January 1, 2003 – December 31, 2003

Contract Coal Suppliers	Tons Purchased (1)	
Peabody Coal Sales	1,876,045	
Black Mountain Resources	185,351	
Arch Coal Sales - West Elk	951,312	
Twenty Mile Coal Company	301,535	
TOTAL Contract Coal		3,314,243

Spot Coal Suppliers	Tons Purchased (1)	
Peabody Coaltrade	589,204	
Mississippi Power Co.	23,906	
Interocean Coal Sales	1,091,739	
TOTAL Spot Coal		1,704,849
GRAND TOTAL COAL PURCHASES		5,019,092

(1) Excludes Plant Scherer: Coal purchases at Plant Scherer are reported on a MMBTU basis. Coal purchases by owner expressed in tons is not maintained.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 23
COMPANY/ Gulf
WITNESS: H. R. Ball (HRB-1)
DATE: 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 1 of 1

This information has been provided pursuant to the Request for Confidential Classification filed on April 1, 2004.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 040001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 29th day of March, 2004

Acknowledged before me this date who is personally known to me and who did not take an oath.

Notary Public, State of Florida at Large

CANDACE KLINGLESMITH
MY COMMISSION # DD 194327
EXPIRES: May 18, 2007
Bonded Thru Notary Public Underwriters

Commission Number: DD194327

Commission Expires: 5-18-07

GULF POWER COMPANY
PROJECTED VS. ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents / KWH Fuel Cost [1]

Period Ending	Projected	Actual	% Difference
March 1995	1.8874	2.0388	8.02
September 1995	2.0456	2.0344	(0.55)
March 1996	1.9795	2.0743	4.79
September 1996	2.0405	1.9639	(3.75)
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5291	1.5696	2.65
December 2000	1.6048	1.6460	2.57
December 2001	1.5782	1.7218	9.10
December 2002	2.0241	2.0505	1.30
December 2003	1.9639	2.1133	7.61
December 2004	2.0934		
December 2005	2.5014		

[1] Line No. 1 from FPSC Schedule A-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 24
COMPANY/ Gulf
WITNESS. H.R. Ball (HRB-2)
DATE: 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. _____ (TAD-1)
Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
January 2003 - December 2003

1.	Estimated over/(under) - recovery for the period January 2003 - December 2003 (Schedule E1-A approved in Order No. PSC-03-1461-FOF-EI dated December 22, 2003)	$ (23,923,505)
2.	Actual over/(under)-recovery for the period January 2003 - December 2003 (DECEMBER 2003 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7and 8)	(21,388,487)
3.	Amount to be refunded/(recovered) in the JANUARY 2005 - DECEMBER 2005 projection period (Line 2 - Line 1)	$ 2,535,018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 25
COMPANY/ GULF
WITNESS. T.A. Davis (TAD-1)
DATE: 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. ____ (TAD -1)
SCHEDULE CCA-1
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
JANUARY 2003 - DECEMBER 2003

1. Estimated over/(under)-recovery for the period JANUARY 2003 - DECEMBER 2003 (Schedule CCE-1a approved in Order No. PSC-03-1461-FOF-EI dated December 22, 2003)	$ 1,058,876
2. Actual over/(under)-recovery for the period JANUARY 2003 - DECEMBER 2003 (Schedule CCA-2 Line 10+11 in the Total column)	2,112,655
3. Amount to be refunded/(recovered) in the JANUARY 2005 - DECEMBER 2005 projection period (Line 2 - Line 1)	$ 1,053,779

SCHEDULE CCA-2
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL TOTAL
1. IIC Payments / (Receipts) ($)	576,317	4,193	192,099	(9,415)	(102,417)	374,563	1,404,921	2,183,978	1,936,562	34,769	(48,418)	32,057	6,579,209
2. Transmission Revenue ($)	(51,592)	(78,086)	(31,701)	(44,371)	(39,430)	(22,413)	(31,968)	(36,890)	(16,169)	(17,100)	(8,525)	(28,942)	(407,187)
3. Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	586,927	(11,691)	222,600	8,416	(79,645)	414,352	1,435,155	2,209,290	1,982,595	79,871	5,259	65,317	6,918,446
5. Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187
6. Jurisdictional Capacity Payments / (Receipts) (Line 4 x 5) ($)	566,395	(11,282)	214,813	8,122	(76,858)	399,857	1,384,952	2,132,006	1,913,241	77,077	5,075	63,033	6,676,429
7. Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	832,086	588,475	600,711	633,690	804,474	850,248	896,302	909,151	797,922	656,741	618,482	1,052,895	9,241,177
8. True-Up Provision ($)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(466,176)
9. Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	793,238	549,627	561,863	594,842	765,626	811,400	857,454	870,303	759,074	617,893	579,634	1,014,047	8,775,001
10. Over/(Under) Recovery (Line 9 - 6) ($)	226,843	560,909	347,050	586,720	842,485	411,543	(527,497)	(1,261,703)	(1,154,167)	540,816	574,559	951,015	2,098,574
11. Interest Provision ($)	(149)	308	796	1,277	2,047	2,500	2,305	1,622	599	361	861	1,554	14,081
12. Beginning Balance True-Up & Interest Provision ($)	(272,479)	(6,937)	593,129	979,823	1,606,668	2,490,048	2,942,939	2,456,595	1,235,362	120,642	700,667	1,314,935	(272,479)
13. True-Up Collected/(Refunded) ($)	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	466,176
14. End Of Period Total Net True-Up (Lines 10 + 11 + 12 + 13) ($)	(6,937)	593,129	979,823	1,606,668	2,490,048	2,942,939	2,456,595	1,235,362	120,642	700,667	1,314,935	2,306,352	

SCHEDULE CCA-3
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	(272,479)	(6,906)	593,188	979,882	1,606,727	2,490,107	2,942,998	2,456,654	1,235,421	120,701	700,726	1,314,994	
3. Ending True-Up Amount Before Interest ($)	(6,757)	592,880	979,086	1,605,450	2,488,059	2,940,496	2,454,349	1,233,799	120,103	700,365	1,314,135	2,304,857	
4. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(279,236)	585,974	1,572,274	2,585,332	4,094,786	5,430,603	5,397,347	3,690,453	1,355,524	821,066	2,014,861	3,619,851	
5. Average True-Up Amount ($)	(139,618)	292,987	786,137	1,292,666	2,047,393	2,715,302	2,698,674	1,845,227	677,762	410,533	1,007,431	1,809,926	
6. Interest Rate - First Day of Reporting Business Month	0.012900	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.010500	0.010600	0.010600	0.010500	0.010000	
7. Interest Rate - First Day of Subsequent Business Month	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.010500	0.010600	0.010600	0.010500	0.010000	0.010600	
8. Total Interest Rate (Lines 5 + 6)	0.025600	0.025200	0.024300	0.023700	0.024000	0.022100	0.020500	0.021100	0.021200	0.021100	0.020500	0.020600	
9. Average Interest Rate	0.012800	0.012600	0.012150	0.011850	0.012000	0.011050	0.010250	0.010550	0.010600	0.010550	0.010250	0.010300	
10. Monthly Average Interest Rate (1/12 Of Line 8)	0.001067	0.001050	0.001013	0.000988	0.001000	0.000921	0.000854	0.000879	0.000883	0.000879	0.000854	0.000858	
11. Interest Provision For the Month (Lines 4 X 9) ($)	(149)	308	796	1,277	2,048	2,502	2,305	1,622	598	361	859	1,554	14,081

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2004 (Sch. E-1B, page 2, line 9)	($29,107,969)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2003 (EXHIBIT No.____(TAD-1), filed April 1, 2004	2,535,018
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2005 - DECEMBER 2005 (Schedule E1, Line 28)	($26,572,951)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005	11,032,273,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.2409

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 26
COMPANY/ Gulf
WITNESS: T. A. Davis (TAD-2)
DATE: 11-08-04

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	28,588,955.96	26,528,981.43	22,286,468.42	26,664,669.64	32,124,877.67	33,132,736.65	$169,326,689.77
	1a	Fuel Cost of Hedging Settlement	(997,750.00)	(164,350.00)	541,100.00	(693,600.00)	(744,900.00)	(1,491,210.00)	(3,550,710.00)
	1b	Fuel Cost of Hedging Support	2,537.49	1,879.56	1,541.14	1,656.50	2,251.24	1,265.75	11,131.68
	2	Fuel Cost of Power Sold	(8,291,799.04)	(9,575,999.98)	(9,263,064.53)	(8,992,603.34)	(11,091,183.10)	(8,244,548.81)	(55,459,198.80)
	3	Fuel Cost of Purchased Power	2,390,298.72	2,420,900.76	4,004,189.98	4,928,139.04	5,591,431.22	4,436,332.60	23,771,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	36,721.00	23,625.00	54,159.00	22,333.00	25,724.00	56,281.00	218,843.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	131,338.97	137,774.76	151,479.14	150,528.35	149,955.63	154,795.10	875,871.95
	6	Adjustment to Fuel Cost	(99,721.17)	111,683.30	(2,332.30)	7,899.11	19,335.24	26,227.54	63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
B	1	Jurisdictional KWH Sales	900,413,364	829,782,367	774,360,621	769,393,414	980,459,512	1,069,388,710	5,323,797,988
	2	Non-Jurisdictional KWH Sales	32,378,859	29,080,350	25,031,604	24,974,940	31,550,354	34,499,450	177,515,557
	3	TOTAL SALES (Lines B1 + B2)	932,792,223	858,862,717	799,392,225	794,368,354	1,012,009,866	1,103,888,160	5,501,313,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.5288%	96.6141%	96.8687%	96.8560%	96.8824%	96.8747%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$22,142,468.41	$20,235,607.77	$18,971,959.87	$18,883,164.05	$24,058,701.90	$26,282,204.72	$130,574,106.72
	2	True-Up Provision	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(11,433,291.96)
	2a	Incentive Provision	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(215,804.58)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$20,200,952.32	$18,294,091.68	$17,030,443.78	$16,941,647.96	$22,117,185.81	$24,340,688.63	$118,925,010.18
	4	Fuel & Net Power Transactions (Line A7)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	21,019,932.27	18,837,946.66	17,229,049.86	21,409,519.62	25,282,185.16	27,213,585.55	$130,992,219.12
	6	Over/(Under) Recovery (Line C3-C5)	(818,979.95)	(543,854.98)	(198,606.08)	(4,467,871.66)	(3,164,999.35)	(2,872,896.92)	($12,067,208.94)
	7	Interest Provision	(17,235.59)	(15,571.20)	(13,363.08)	(14,076.17)	(16,157.34)	(19,613.63)	($96,017.02)
	8	Prior Period Adjustment	0.00	0.00	706,360.01	0.00	0.00	0.00	$706,360.01
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - JUNE 2004							($11,456,865.95)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		39,370,000.00	39,635,000.00	36,094,000.00	32,383,000.00	27,021,000.00	29,016,000.00	$372,845,689.77
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	($3,550,710.00)
	1b	Fuel Cost of Hedging Support		2,757.00	2,757.00	2,757.00	2,757.00	2,757.00	2,759.00	$27,675.68
	2	Fuel Cost of Power Sold		(14,209,000.00)	(14,260,000.00)	(13,520,000.00)	(9,400,000.00)	(10,667,000.00)	(10,356,000.00)	($127,871,198.80)
	3	Fuel Cost of Purchased Power		3,401,000.00	3,812,000.00	845,000.00	1,581,000.00	1,538,000.00	2,563,000.00	$37,511,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$218,843.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		257,000.00	257,000.00	249,000.00	257,000.00	249,000.00	257,000.00	$2,401,871.95
	6	Adjustment to Fuel Cost		0.00	0.00	0.00	0.00	0.00	0.00	$63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
B	1	Jurisdictional KWH Sales		1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	10,840,883,988
	2	Non-Jurisdictional KWH Sales		38,218,000	38,147,000	33,249,000	29,300,000	27,425,000	30,672,000	374,526,557
	3	TOTAL SALES (Lines B1 + B2)		1,159,498,000	1,159,366,000	961,791,000	850,017,000	738,495,000	844,930,000	11,215,410,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7039%	96.7097%	96.5430%	96.5530%	96.2864%	96.3699%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$27,552,437.45	$27,550,938.53	$22,816,419.96	$20,166,910.85	$17,472,631.01	$20,008,198.32	$266,141,642.84
	2	True-Up Provision		(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.74)	($22,866,584.00)
	2a	Incentive Provision		(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.51)	($431,609.24)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$25,610,921.36	$25,609,422.44	$20,874,903.87	$18,225,394.76	$15,531,114.92	$18,066,682.07	$242,843,449.60
	4	Fuel & Net Power Transactions (Line A7)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		27,891,273.30	28,497,804.86	22,868,455.65	23,984,859.75	17,482,199.42	20,717,405.40	$272,434,217.50
	6	Over/(Under) Recovery (Line C3-C5)		(2,280,351.94)	(2,888,382.42)	(1,993,551.78)	(5,759,464.99)	(1,951,084.50)	(2,650,723.33)	($29,590,767.90)
	7	Interest Provision	(2)	(10,240.59)	(20,976.82)	(21,526.54)	(23,495.12)	(25,444.66)	(25,860.41)	($223,561.00)
	8	Prior Period Adjustment		0.00	0.00	0.00	0.00	0.00	0.00	$706,360.01
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - DECEMBER 2004								($29,107,968.89)

Note 1: Estimated Revenues based on the 2004 Fuel Factor excluding revenue taxes of 2.4572 ¢/KWH
Note 2: Interest Calculated for July through December at June's rate of 0.0988

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	372,845,690	340,226,335	32,619,355	9.59	15,605,983,000	16,251,250,000	(645,267,000)	(3.97)	2.3891	2.0935	0.2956	14.12
1a	Fuel Cost of Heding Settlement	(3,550,710)	0										
2	Hedging Support Costs	27,676	33,086	(5,410)	(16.35)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	2,401,872	19,205	2,382,667	12,406.49	78,019,000	790,000	77,229,000	9,775.82	3.0786	2.431	0.6476	26.64
5	Adjustment to Fuel Cost	63,092											
5	TOTAL COST OF GENERATED POWER	371,787,619	340,278,626	31,508,993	9.26	15,684,002,000	16,252,040,000	(568,038,000)	(3.50)	2.3705	2.0938	0.2767	13.22
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	37,511,292	12,776,000	24,735,292	193.61	1,032,349,249	477,038,000	555,311,249	116.41	3.6336	2.6782	0.9554	35.67
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	218,843	0	218,843	#N/A	6,578,895	0	6,578,895	#N/A	3.3264	#N/A	#N/A	#N/A
12	TOTAL COST OF PURCHASED POWER	37,730,135	12,776,000	24,954,135	195.32	1,038,928,144	477,038,000	561,890,144	117.79	3.6316	2.6782	0.9534	35.60
13	Total Available KWH (Lines 5 + Line 12)	409,517,754	353,054,626	56,463,128	15.99	16,722,930,144	16,729,078,000	(6,147,856)	(0.04)				
14	Fuel Cost of Economy Sales (A6)	(61,778,195)	(2,289,000)	(59,489,195)	(2,598.92)	(160,861,993)	(74,677,000)	(86,184,993)	(115.41)	(38.4045)	(3.0652)	(35.3393)	(1,152.92)
15	Gain on Economy Sales (A6)	(15,752,402)	(363,000)	(15,369,402)	(4,012.90)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(16,568,637)	(26,458,000)	9,889,363	37.38	(1,431,724,048)	(1,561,911,000)	130,186,952	8.34	(1.1573)	(1.6940)	0.5367	31.68
17	Fuel Cost of Other Power Sales (A6)	(33,771,965)	(79,395,000)	45,623,035	57.46	(3,202,473,809)	(3,440,414,000)	237,940,191	6.92	(1.0546)	(2.3077)	1.2531	54.30
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(127,871,199)	(108,525,000)	(19,346,199)	(17.83)	(4,795,059,850)	(5,077,002,000)	281,942,150	5.55	(2.6667)	(2.1376)	(0.5291)	(24.75)
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5+12+18+19)	281,646,556	244,529,626	37,116,930	15.18	11,927,870,294	11,652,076,000	275,794,294	2.37	2.3612	2.0986	0.2626	12.51
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	560,171	545,195	14,976	2.75	23,723,999	25,979,000	(2,255,001)	(8.68)	2.3612	2.0986	0.2626	12.51
23	T & D Losses *	16,262,429	14,395,200	1,867,229	12.97	688,735,750	685,943,000	2,792,750	0.41	2.3612	2.0986	0.2626	12.51
24	TERRITORIAL (SYSTEM) SALES	281,646,556	244,529,626	37,116,930	15.18	11,215,410,545	10,940,154,000	275,256,545	2.52	2.5112	2.2352	0.2760	12.35
25	Wholesale Sales	9,402,909	8,348,785	1,054,124	12.63	374,526,557	373,514,000	1,012,557	0.27	2.5106	2.2352	0.2754	12.32
26	Jurisdictional Sales	272,243,647	236,180,841	36,062,806	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5113	2.2352	0.2761	12.35
26a	Jurisdictional Loss Multiplier***	1.0007	1.0007										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0007)	272,434,218	236,346,168	36,088,050	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5130	2.2367	0.2763	12.35
28	TRUE-UP **	22,866,584	22,866,584	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.2109	0.2164	(0.0055)	(2.54)
29	TOTAL JURISDICTIONAL FUEL COST	295,300,802	259,212,752	36,088,050	13.92	10,840,883,988	10,566,640,000	274,243,988	2.60	2.7239	2.4531	0.2708	11.04
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									2.7259	2.4549	0.2710	11.04
32	GPIF Reward / (Penalty) **	431,920	431,920	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.0040	0.0041	(0.0001)	(2.44)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.7299	2.459	0.2709	11.02
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.730	2.459	0.271	11.02

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 8 months actual and 4 months estimate.

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2005 - December 2005

1	Estimated over/(under)-recovery, January 2004 - December 2004 (Schedule CCE-1b-1, Line 15)	$817,151
2	Final True-Up, January 2003 - December 2003 (Exhibit No.____(TAD-1), filed April 1, 2004	1,053,779
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2005 - December 2005)	$1,870,930
4	Jurisdictional KWH sales, January 2005 - December 2005	11,032,273,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0170)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2004 - December 2004

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,265,929	353,640	464,415	7,329	41,220	1,632,176	6,286,325	5,666,244	2,360,242	199,560	67,649	144,635	18,731,384
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(56,915)	(37,118)	(31,779)	(15,372)	(28,687)	(20,062)	(13,000)	(7,000)	(11,000)	(7,000)	(9,000)	(7,000)	(243,933)
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	1,271,216	378,724	514,838	54,159	74,735	1,674,316	6,335,527	5,743,446	2,411,444	254,762	120,851	199,837	19,233,875
5	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,226,747	365,476	496,828	52,264	72,122	1,808,750	6,113,902	5,542,533	2,327,069	245,869	116,623	192,846	18,561,047
7	Retail KWH Sales							1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,256,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.167	0.167	0.167	0.167	0.167	0.167	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	1,606,955	1,364,327	1,256,441	1,242,257	1,612,485	1,794,023	1,872,536	1,872,436	1,550,665	1,370,597	1,187,467	1,359,811	18,108,022
10	Revenue Taxes (Line 9 x .00072) ($)*	1,156	997	904	894	1,161	1,292	1,348	1,348	1,116	987	855	979	13,037
11	True-Up Provision ($)	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	1,252,572
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	1,709,180	1,467,711	1,358,918	1,345,744	1,715,705	1,897,112	1,975,571	1,975,469	1,653,930	1,473,991	1,291,013	1,463,213	19,347,557
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	462,433	1,122,235	862,090	1,293,480	1,643,583	88,362	(4,138,331)	(3,567,064)	(673,159)	1,228,122	1,174,390	1,270,367	786,510
14	Interest Provision ($)	2,173	2,676	3,337	4,240	5,547	7,108	5,015	1,110	(1,066)	(916)	166	1,271	30,641
15	Total Estimated True-Up for the Period January 2003 - December 2003 (Lines 13 + 14) ($)													817,151

NOTE 1: Interest is Calculated for July - December at June's rate of 0.0966 %
NOTE 2: Actual IIC Payments for January through June include Market Capacity Payments

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	393,442,768	15,728,660,000	2.5014
2	Nuclear Fuel Disposal Costs		E-2			#N/A
3	Coal Car Investment					#N/A
4	Other Generation		E-3	2,795,957	101,010,000	2.7680
5	Hedging Administration Costs		E-2	33,086		#N/A
6	**Total Cost of Generated Power**	(Line 1 - 5)		396,271,811	15,829,670,000	2.5033
7	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
8	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	18,804,000	536,336,000	3.5060
10	Energy Cost of Schedule E Economy Purch.		E-9			#N/A
11	Capacity Cost of Schedule E Economy Purchases		E-2			#N/A
12	Energy Payments to Qualifying Facilities		E-8			#N/A
13	**Total Cost of Purchased Power**	(Line 6 - 12)		18,804,000	536,336,000	3.5060
14	**Total Available KWH**	(Line 5 + 13)			16,366,006,000	
15	Fuel Cost of Economy Sales		E-6	(2,993,000)	(73,662,000)	4.0632
16	Gain on Economy Sales		E-6	(2,627,000)		#N/A
17	Fuel Cost of Unit Power Sales		E-6	(26,327,000)	(1,404,369,000)	1.8746
18	Fuel Cost of Other Power Sales			(89,596,000)	(2,743,151,000)	3.2662
19	**Total Fuel Cost & Gains on Power Sales**	(Line 15 -18)		(121,543,000)	(4,221,182,000)	2.8794
20	Net Inadvertant Interchange			0	0	#N/A
21	**Total Fuel & Net Power Trans.**	(Line 6+13+19+20)		293,532,811	12,144,824,000	2.4169
22	Net Unbilled Sales *			0	0	#N/A
23	Company Use *			591,923	24,491,000	2.4169
24	T & D Losses *			17,104,401	707,700,000	2.4169
25	**System KWH Sales**			293,532,811	11,412,633,000	2.5720
26	Wholesale KWH Sales			9,782,859	380,360,000	2.5720
27	Jurisdictional KWH Sales			283,749,952	11,032,273,000	2.5720
27a	Jurisdictional Line Loss Multiplier			1.0007		1.0007
28	Jurisdictional KWH Sales Adjusted for Line Losses			283,948,577	11,032,273,000	2.5738
29	**True-Up ****			26,572,951	11,032,273,000	0.2409
30	**Total Jurisdictional Fuel Cost**			310,521,528	11,032,273,000	2.8147
31	Revenue Tax Factor					1.00072
32	Fuel Factor Adjusted For Revenue Taxes					2.8167
33	GPIF Reward/(Penalty) **			625,280	11,032,273,000	0.0057
34	Fuel Factor Adjusted for GPIF					2.8224
35	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**2.822**

*For informational purposes only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 27
COMPANY/ Gulf
WITNESS: T.A. Davis (TAD-3)
DATE: 11-08-04

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2004 (Sch. E-1B, page 2, line 9)	($29,107,969)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2003 (EXHIBIT No.____(TAD-1), filed April 1, 2004	2,535,018
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2005 - DECEMBER 2005 (Schedule E1, Line 28)	($26,572,951)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005	11,032,273,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.2409

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	28,588,955.96	26,528,981.43	22,286,468.42	26,664,669.64	32,124,877.67	33,132,736.65	$169,326,689.77
	1a	Fuel Cost of Hedging Settlement	(997,750.00)	(164,350.00)	541,100.00	(693,600.00)	(744,900.00)	(1,491,210.00)	(3,550,710.00)
	1b	Fuel Cost of Hedging Support	2,537.49	1,879.56	1,541.14	1,656.50	2,251.24	1,265.75	11,131.68
	2	Fuel Cost of Power Sold	(8,291,799.04)	(9,575,999.98)	(9,263,064.53)	(8,992,603.34)	(11,091,183.10)	(8,244,548.81)	(55,459,198.80)
	3	Fuel Cost of Purchased Power	2,390,298.72	2,420,900.76	4,004,189.98	4,928,139.04	5,591,431.22	4,436,332.60	23,771,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	36,721.00	23,625.00	54,159.00	22,333.00	25,724.00	56,281.00	218,843.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	131,338.97	137,774.76	151,479.14	150,528.35	149,955.63	154,795.10	875,871.95
	6	Adjustment to Fuel Cost	(99,721.17)	111,683.30	(2,332.30)	7,899.11	19,335.24	26,227.54	63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
B	1	Jurisdictional KWH Sales	900,413,364	829,782,367	774,360,621	769,393,414	980,459,512	1,069,388,710	5,323,797,988
	2	Non-Jurisdictional KWH Sales	32,378,859	29,080,350	25,031,604	24,974,940	31,550,354	34,499,450	177,515,557
	3	TOTAL SALES (Lines B1 + B2)	932,792,223	858,862,717	799,392,225	794,368,354	1,012,009,866	1,103,888,160	5,501,313,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.5288%	96.6141%	96.8687%	96.8560%	96.8824%	96.8747%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$22,142,468.41	$20,235,607.77	$18,971,959.87	$18,883,164.05	$24,058,701.90	$26,282,204.72	$130,574,106.72
	2	True-Up Provision	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(11,433,291.96)
	2a	Incentive Provision	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(215,804.58)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$20,200,952.32	$18,294,091.68	$17,030,443.78	$16,941,647.96	$22,117,185.81	$24,340,688.63	$118,925,010.18
	4	Fuel & Net Power Transactions (Line A7)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	21,019,932.27	18,837,946.66	17,229,049.86	21,409,519.62	25,282,185.16	27,213,585.55	$130,992,219.12
	6	Over/(Under) Recovery (Line C3-C5)	(818,979.95)	(543,854.98)	(198,606.08)	(4,467,871.66)	(3,164,999.35)	(2,872,896.92)	($12,067,208.94)
	7	Interest Provision	(17,235.59)	(15,571.20)	(13,363.08)	(14,076.17)	(16,157.34)	(19,613.63)	($96,017.02)
	8	Prior Period Adjustment	0.00	0.00	706,360.01	0.00	0.00	0.00	$706,360.01
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - JUNE 2004**							($11,456,865.95)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		39,370,000.00	39,635,000.00	36,094,000.00	32,383,000.00	27,021,000.00	29,016,000.00	$372,845,689.77
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	($3,550,710.00)
	1b	Fuel Cost of Hedging Support		2,757.00	2,757.00	2,757.00	2,757.00	2,757.00	2,759.00	$27,675.68
	2	Fuel Cost of Power Sold		(14,209,000.00)	(14,260,000.00)	(13,520,000.00)	(9,400,000.00)	(10,667,000.00)	(10,356,000.00)	($127,871,198.80)
	3	Fuel Cost of Purchased Power		3,401,000.00	3,812,000.00	845,000.00	1,581,000.00	1,538,000.00	2,563,000.00	$37,511,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$218,843.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		257,000.00	257,000.00	249,000.00	257,000.00	249,000.00	257,000.00	$2,401,871.95
	6	Adjustment to Fuel Cost		0.00	0.00	0.00	0.00	0.00	0.00	$63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
B	1	Jurisdictional KWH Sales		1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	10,840,883,988
	2	Non-Jurisdictional KWH Sales		38,218,000	38,147,000	33,249,000	29,300,000	27,425,000	30,672,000	374,526,557
	3	TOTAL SALES (Lines B1 + B2)		1,159,498,000	1,159,366,000	961,791,000	850,017,000	738,495,000	844,930,000	11,215,410,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7039%	96.7097%	96.5430%	96.5530%	96.2864%	96.3699%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$27,552,437.45	$27,550,938.53	$22,816,419.96	$20,166,910.85	$17,472,631.01	$20,008,198.32	$266,141,642.84
	2	True-Up Provision		(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.74)	($22,866,584.00)
	2a	Incentive Provision		(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.51)	($431,609.24)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$25,610,921.36	$25,609,422.44	$20,874,903.87	$18,225,394.76	$15,531,114.92	$18,066,682.07	$242,843,449.60
	4	Fuel & Net Power Transactions (Line A7)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		27,891,273.30	28,497,804.86	22,868,455.65	23,984,859.75	17,482,199.42	20,717,405.40	$272,434,217.50
	6	Over/(Under) Recovery (Line C3-C5)		(2,280,351.94)	(2,888,382.42)	(1,993,551.78)	(5,759,464.99)	(1,951,084.50)	(2,650,723.33)	($29,590,767.90)
	7	Interest Provision	(2)	(10,240.59)	(20,976.82)	(21,526.54)	(23,495.12)	(25,444.66)	(25,860.41)	($223,561.00)
	8	Prior Period Adjustment		0.00	0.00	0.00	0.00	0.00	0.00	$706,360.01
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - DECEMBER 2004**								($29,107,968.89)

Note 1: Estimated Revenues based on the 2004 Fuel Factor excluding revenue taxes of 2.4572 ¢/KWH
Note 2: Interest Calculated for July through December at June's rate of 0.0988

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	372,845,690	340,226,335	32,619,355	9.59	15,605,983,000	16,251,250,000	(645,267,000)	(3.97)	2.3891	2.0935	0.2956	14.12
1a	Fuel Cost of Heding Settlement	(3,550,710)	0										
2	Hedging Support Costs	27,676	33,086	(5,410)	(16.35)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	2,401,872	19,205	2,382,667	12,406.49	78,019,000	790,000	77,229,000	9,775.82	3.0786	2.431	0.6476	26.64
5	Adjustment to Fuel Cost	63,092											
5	TOTAL COST OF GENERATED POWER	371,787,619	340,278,626	31,508,993	9.26	15,684,002,000	16,252,040,000	(568,038,000)	(3.50)	2.3705	2.0938	0.2767	13.22
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	37,511,292	12,776,000	24,735,292	193.61	1,032,349,249	477,038,000	555,311,249	116.41	3.6336	2.6782	0.9554	35.67
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	218,843	0	218,843	#N/A	6,578,895	0	6,578,895	#N/A	3.3264	#N/A	#N/A	#N/A
12	TOTAL COST OF PURCHASED POWER	37,730,135	12,776,000	24,954,135	195.32	1,038,928,144	477,038,000	561,890,144	117.79	3.6316	2.6782	0.9534	35.60
13	Total Available KWH (Lines 5 + Line 12)	409,517,754	353,054,626	56,463,128	15.99	16,722,930,144	16,729,078,000	(6,147,856)	(0.04)				
14	Fuel Cost of Economy Sales (A6)	(61,778,195)	(2,289,000)	(59,489,195)	(2,598.92)	(160,861,993)	(74,677,000)	(86,184,993)	(115.41)	(38.4045)	(3.0652)	(35.3393)	(1,152.92)
15	Gain on Economy Sales (A6)	(15,752,402)	(383,000)	(15,369,402)	(4,012.90)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(16,568,637)	(26,458,000)	9,889,363	37.38	(1,431,724,048)	(1,561,911,000)	130,186,952	8.34	(1.1573)	(1.6940)	0.5367	31.68
17	Fuel Cost of Other Power Sales (A6)	(33,771,965)	(79,395,000)	45,623,035	57.46	(3,202,473,809)	(3,440,414,000)	237,940,191	6.92	(1.0546)	(2.3077)	1.2531	54.30
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(127,871,199)	(108,525,000)	(19,346,199)	(17.83)	(4,795,059,850)	(5,077,002,000)	281,942,150	5.55	(2.6667)	(2.1376)	(0.5291)	(24.75)
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	281,646,556	244,529,626	37,116,930	15.18	11,927,870,294	11,652,076,000	275,794,294	2.37	2.3612	2.0986	0.2626	12.51
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	560,171	545,195	14,976	2.75	23,723,999	25,979,000	(2,255,001)	(8.68)	2.3612	2.0986	0.2626	12.51
23	T & D Losses *	16,262,429	14,395,200	1,867,229	12.97	688,735,750	685,943,000	2,792,750	0.41	2.3612	2.0986	0.2626	12.51
24	TERRITORIAL (SYSTEM) SALES	281,646,556	244,529,626	37,116,930	15.18	11,215,410,545	10,940,154,000	275,256,545	2.52	2.5112	2.2352	0.2760	12.35
25	Wholesale Sales	9,402,909	8,348,785	1,054,124	12.63	374,526,557	373,514,000	1,012,557	0.27	2.5106	2.2352	0.2754	12.32
26	Jurisdictional Sales	272,243,647	236,180,841	36,062,806	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5113	2.2352	0.2761	12.35
26a	Jurisdictional Loss Multiplier***	1.0007	1.0007										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0007)	272,434,218	236,346,168	36,088,050	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5130	2.2367	0.2763	12.35
28	TRUE-UP **	22,866,584	22,866,584	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.2109	0.2164	(0.0055)	(2.54)
29	TOTAL JURISDICTIONAL FUEL COST	295,300,802	259,212,752	36,088,050	13.92	10,840,883,988	10,566,640,000	274,243,988	2.60	2.7239	2.4531	0.2708	11.04
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									2.7259	2.4549	0.2710	11.04
32	GPIF Reward / (Penalty) **	431,920	431,920	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.0040	0.0041	(0.0001)	(2.44)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.7299	2.459	0.2709	11.02
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									2.730	2.459	0.271	11.02

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts included in the Estimated/Actual Column represent 8 months actual and 4 months estimate.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	625,280
	B. True-Up (Over)/Under Recovered	$	26,572,951
2.	TOTAL SALES (KWH)		11,032,273,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.0057
	B. True-Up Factor		0.2409

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		NET ENERGY FOR LOAD %
	On-Peak	29.83
	Off-Peak	70.17
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	2.5720	3.0536	2.3671
Jurisdictional Loss Factor	1.0007	1.0007	1.0007
Jurisdictional Fuel Factor	2.5738	3.0557	2.3688
GPIF	0.0057	0.0057	0.0057
True-Up	0.2409	0.2409	0.2409
TOTAL	2.8204	3.3023	2.6154
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	2.8223	3.3047	2.6173
Recovery Factor Rounded to the Nearest .001 ¢/KWH	2.822	3.305	2.617

HOURS:	ON-PEAK	25.59%
	OFF-PEAK	74.41%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, SBS (1)	2.822	1.00526	2.837
B	LP/LPT, SBS (2)	2.822	0.98890	2.791
C	PX, RTP, CSA	2.822	0.98063	2.767
D	OS-I/II	2.822	1.00529	2.808 *

		TOU
A	On-Peak	3.322
	Off-Peak	2.631
B	On-Peak	3.268
	Off-Peak	2.588
C	On-Peak	3.241
	Off-Peak	2.567
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	3.305 ¢ / KWH	x	0.2559	=	0.846	¢ / KWH
	Off-Peak	2.617 ¢ / KWH	x	0.7441	=	1.947	¢ / KWH
						2.793	¢ / KWH
			Line Loss Multiplier		x	1.00529	
						2.808	¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	32,946,451	24,264,379	25,545,736	28,691,817	35,623,850	38,297,282	43,971,039	44,949,349	35,985,305	31,955,668	24,998,301	26,213,591	393,442,768
1a	Other Generation	237,494	214,520	237,494	229,744	237,494	229,744	237,494	237,494	229,744	237,494	229,744	237,497	2,795,957
2	Fuel Cost of Power Sold	(14,111,000)	(8,057,000)	(6,311,000)	(10,415,000)	(11,464,000)	(9,469,000)	(12,630,000)	(13,918,000)	(10,248,000)	(7,460,000)	(8,189,000)	(9,271,000)	(121,543,000)
3	Fuel Cost of Purchased Power	604,000	1,205,000	4,290,000	986,000	1,065,000	1,559,000	1,607,000	953,000	1,696,000	1,969,000	2,179,000	691,000	18,804,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases													0
5	Hedging Administrative Cost	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,759	33,086
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	19,679,702	17,629,656	23,764,987	19,495,318	25,465,101	30,619,783	33,188,290	32,224,600	27,665,806	26,704,919	19,220,802	17,873,847	293,532,811
6	System KWH Sold	890,307,000	788,402,000	813,345,000	820,632,000	1,034,272,000	1,144,402,000	1,207,547,000	1,190,308,000	994,251,000	880,832,000	777,777,000	870,558,000	11,412,633,000
6a	Jurisdictional % of Total Sales	96.3881	96.6811	96.5483	96.7326	96.8985	96.9623	96.7891	96.7485	96.6018	96.6105	96.4049	96.4130	96.6672
7	Cost per KWH Sold (¢/KWH)	2.2104	2.2361	2.9219	2.3756	2.4621	2.6756	2.7484	2.7072	2.7826	3.0318	2.4712	2.0531	2.5720
7a	Jurisdictional Loss Multiplier	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007
7b	Jurisdictional Cost (¢/KWH)	2.2119	2.2377	2.9239	2.3773	2.4638	2.6775	2.7503	2.7091	2.7845	3.0339	2.4729	2.0545	2.5738
8	GPIF (¢ / KWH) *	0.0061	0.0068	0.0066	0.0066	0.0052	0.0047	0.0045	0.0045	0.0054	0.0061	0.0069	0.0062	0.0057
9	True-Up (¢/KWH) *	0.2580	0.2905	0.2820	0.2790	0.2210	0.1996	0.1895	0.1923	0.2306	0.2602	0.2953	0.2638	0.2409
10	TOTAL	2.4760	2.5350	3.2125	2.6629	2.6900	2.8818	2.9443	2.9059	3.0205	3.3002	2.7751	2.3245	2.8204
11	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
12	Recovery Factor Adjusted for Taxes	2.4778	2.5368	3.2148	2.6648	2.6919	2.8839	2.9464	2.9080	3.0227	3.3026	2.7771	2.3262	2.8223
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	2.478	2.537	3.215	2.665	2.692	2.884	2.946	2.908	3.023	3.303	2.777	2.326	2.822

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
2	LIGHTER OIL (B.L.)	49,536	43,639	37,416	44,095	50,979	51,248	51,487	51,699	51,889	45,042	52,155	51,401	580,586
3	COAL excluding Scherer	20,669,919	13,309,357	10,668,262	14,836,507	20,956,684	21,837,162	24,450,749	24,923,577	19,917,001	14,718,364	14,515,885	21,201,344	222,004,811
3a	COAL at Scherer	2,587,366	2,346,801	2,608,068	2,526,529	2,631,446	2,562,132	2,648,283	2,648,510	2,561,843	2,616,667	2,531,067	2,616,960	30,885,672
4	GAS - Generation	9,598,119	8,534,881	12,204,542	11,249,458	11,946,049	13,808,048	16,780,243	17,263,083	13,417,818	14,557,234	7,862,381	2,303,258	139,525,114
4a	GAS (B.L.)	41,511	29,701	27,448	35,228	38,692	38,692	40,277	40,335	36,754	18,361	36,813	40,628	424,440
6	OTHER - C.T.	0	0	0	0	0	0	0	22,145	0	0	0	0	22,145
6a	OTHER GENERATION	237,494	214,520	237,494	229,744	237,494	229,744	237,494	237,494	229,744	237,494	229,744	237,497	2,795,957
7	TOTAL ($)	33,183,945	24,478,899	25,783,230	28,921,561	35,861,344	38,527,026	44,208,533	45,186,843	36,215,049	32,193,162	25,228,045	26,451,088	396,238,725
	SYSTEM NET GEN. (MWH)													
10	COAL	1,259,070	884,630	723,270	962,210	1,261,340	1,262,440	1,359,550	1,365,160	1,114,410	860,760	848,340	1,217,890	13,119,070
11	GAS	147,270	199,290	241,320	232,950	208,120	246,310	301,250	303,570	250,740	263,220	189,940	25,390	2,609,370
13	OTHER - C.T.	0	0	0	0	0	0	0	220	0	0	0	0	220
13a	OTHER GENERATION	8,580	7,750	8,580	8,300	8,580	8,300	8,580	8,580	8,300	8,580	8,300	8,580	101,010
14	TOTAL (MWH)	1,414,920	1,091,670	973,170	1,203,460	1,478,040	1,517,050	1,669,380	1,677,530	1,373,450	1,132,560	1,046,580	1,251,860	15,829,670
	UNITS OF FUEL BURNED													
16	LIGHTER OIL (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
17	COAL excl. Scherer (TON)	497,555	333,691	260,179	368,320	500,178	502,355	544,192	545,338	437,325	319,420	317,421	483,439	5,109,413
18	GAS-all (MCF)	1,202,853	1,066,934	1,698,797	1,468,005	1,437,812	1,709,249	2,059,273	2,127,068	1,738,263	1,910,114	1,087,930	213,316	17,719,614
20	OTHER - C.T. (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
	BTU'S BURNED (MMBTU)													
23	COAL + GAS B.L. + OIL B.L.	12,901,722	8,929,778	7,474,597	9,846,650	13,004,076	12,984,311	13,998,002	14,010,241	11,456,996	8,863,489	8,724,848	12,492,959	134,687,669
24	GAS-Generation	1,233,067	1,094,692	1,745,511	1,506,173	1,475,075	1,754,654	2,115,179	2,185,008	1,784,539	1,964,484	1,114,696	213,843	18,186,921
26	OTHER - C.T.	0	0	0	0	0	0	0	3,151	0	0	0	0	3,151
27	TOTAL (MMBTU)	14,134,789	10,024,470	9,220,108	11,352,823	14,479,151	14,738,965	16,113,181	16,198,400	13,241,535	10,827,973	9,839,544	12,706,802	152,877,741

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
30	COAL	88.99	81.03	74.32	79.95	85.34	83.22	81.44	81.38	81.14	76.00	81.06	97.28	82.88
31	GAS-Generation	10.41	18.26	24.80	19.36	14.08	16.23	18.05	18.10	18.26	23.24	18.15	2.03	16.48
33	OTHER - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
33a	OTHER GENERATION	0.60	0.71	0.88	0.69	0.58	0.55	0.51	0.51	0.60	0.76	0.79	0.69	0.64
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
36	LIGHTER OIL ($/BBL)	41.55	41.80	41.72	42.20	42.77	42.99	43.19	43.37	43.53	44.15	43.75	43.86	42.93
37	COAL ($/TON)*	41.54	39.89	41.00	40.28	41.90	43.47	44.93	45.70	45.54	46.08	45.73	43.86	43.45
38	GAS + B.L. ($/MCF)	8.01	8.03	7.20	7.69	8.34	8.10	8.17	8.13	7.74	7.63	7.26	10.99	7.90
40	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	41.51	#N/A	#N/A	#N/A	#N/A	41.47
	FUEL COST $ / MMBTU													
43	COAL + GAS B.L. + OIL B.L.	1.81	1.76	1.78	1.77	1.82	1.88	1.94	1.97	1.97	1.96	1.96	1.91	1.88
44	GAS-Generation	7.78	7.80	6.99	7.47	8.10	7.87	7.93	7.90	7.52	7.41	7.05	10.77	7.67
46	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	7.03	#N/A	#N/A	#N/A	#N/A	7.03
47	TOTAL ($/MMBTU)	2.35	2.44	2.80	2.55	2.48	2.61	2.74	2.79	2.73	2.97	2.56	2.08	2.59
	BTU BURNED BTU / KWH													
50	COAL + GAS B.L. + OIL B.L.	10,247	10,094	10,334	10,233	10,310	10,285	10,296	10,263	10,281	10,297	10,285	10,258	10,267
51	GAS-Generation	8,373	5,493	7,233	6,466	7,088	7,124	7,021	7,198	7,117	7,463	5,869	8,422	6,970
53	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	14,323	#N/A	#N/A	#N/A	#N/A	14,323
	TOTAL (BTU/KWH)	10,051	9,248	9,559	9,499	9,853	9,769	9,702	9,706	9,700	9,634	9,477	10,220	9,720
	FUEL COST CENTS / KWH													
57	COAL + GAS B.L. + OIL B.L.	1.85	1.78	1.84	1.81	1.88	1.94	2.00	2.03	2.03	2.02	2.02	1.96	1.94
58	GAS-Generation	6.52	4.28	5.06	4.83	5.74	5.61	5.57	5.69	5.35	5.53	4.14	9.07	5.35
60	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	10.07	#N/A	#N/A	#N/A	#N/A	10.07
61	TOTAL (¢/KWH)	2.35	2.24	2.65	2.40	2.43	2.54	2.65	2.69	2.64	2.84	2.41	2.11	2.50

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	2													
3	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
4	3													
5	Crist 4	78.0	47,560	82.0	99.5	82.4	10,854	Coal	21,808	11,835	516,219	993,670	2.09	45.56
6	4							Gas - G						
7	Crist 5	80.0	42,080	70.7	89.0	79.4	10,772	Coal	19,149	11,835	453,266	872,491	2.07	45.56
8	5							Gas - G						
9	Crist 6	302.0	179,720	80.0	97.4	82.1	10,790	Coal	81,925	11,835	1,939,225	3,732,811	2.08	45.56
10	6							Gas - G						
11	Crist 7	477.0	266,600	75.1	85.9	87.5	10,181	Coal	114,665	11,835	2,714,207	5,224,572	1.96	45.56
12	7							Gas - G						
13	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	87,007	8,761	1,524,461	2,587,366	1.74	29.74
14	Scholz 1	46.0	10,770	31.5	89.5	35.2	13,552	Coal	5,708	12,786	145,958	302,803	2.81	53.05
15	Scholz 2	46.0	12,090	35.3	87.0	40.6	12,505	Coal	5,912	12,786	151,189	313,655	2.59	53.05
16	Smith 1	162.0	99,730	82.7	98.4	84.1	10,183	Coal	42,324	11,998	1,015,574	1,670,989	1.68	39.48
17	Smith 2	189.0	80,780	57.4	67.1	85.6	9,908	Coal	33,357	11,998	800,407	1,316,962	1.63	39.48
18	Smith 3	531.0	147,270	37.3	88.4	42.2	8,373	Gas - G	1,197,152	1,030	1,233,067	9,598,119	6.52	8.02
19	Smith A (CT)	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
20	Other Generation		8,580									237,494	2.77	#N/A
21	Daniel 1 (1)	257.0	185,320	96.9	96.9	100.0	10,092	Coal	89,021	10,504	1,870,199	3,217,402	1.74	36.14
22	Daniel 2 (1)	257.0	185,630	97.1	97.3	99.8	9,471	Coal	83,686	10,504	1,758,106	3,024,564	1.63	36.14
23	Gas,BL							Gas	5,701	1,030	5,871	41,511	#N/A	7.28
	Ltr. Oil							Oil	1,192	140,606	7,040	49,536	#N/A	41.55
		2,734.8	1,414,920	69.5	90.9	76.5	10,051				14,134,789	33,183,945	2.35	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,350	88.4	99.3	89.1	10,478	Coal	20,431	11,885	485,654	885,766	1.91	43.35
4	4							Gas - G						
5	Crist 5	80.0	41,320	76.9	87.9	87.4	10,543	Coal	18,327	11,885	435,642	794,551	1.92	43.35
6	5							Gas - G						
7	Crist 6	302.0	174,930	86.2	97.5	88.4	10,211	Coal	75,145	11,885	1,786,231	3,257,838	1.86	43.35
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	210.8	134,420	94.9	94.5	100.4	10,244	Coal	78,551	8,765	1,377,012	2,346,801	1.75	29.88
12	Scholz 1	46.0	15,710	50.8	85.0	59.8	10,256	Coal	6,443	12,505	161,128	388,962	2.48	60.37
13	Scholz 2	46.0	15,690	50.8	84.5	60.1	10,389	Coal	6,518	12,505	163,004	393,490	2.51	60.37
14	Smith 1	162.0	96,050	88.2	98.5	89.6	10,260	Coal	41,062	12,000	985,494	1,619,470	1.69	39.44
15	Smith 2	189.0	68,020	53.6	60.4	88.7	10,053	Coal	28,491	12,000	683,786	1,123,672	1.65	39.44
16	Smith 3	531.0	199,290	55.8	88.4	63.2	5,493	Gas - G	1,062,808	1,030	1,094,692	8,534,881	4.28	8.03
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		7,750				0					214,520	2.77	#N/A
19	Daniel 1 (1)	257.0	136,750	79.2	79.5	99.6	9,932	Coal	65,617	10,349	1,358,196	2,316,202	1.69	35.30
20	Daniel 2 (1)	257.0	155,390	90.0	90.3	99.6	9,545	Coal	71,657	10,349	1,483,217	2,529,406	1.63	35.30
21	Gas,BL							Gas	4,126	1,030	4,249	29,701	#N/A	7.20
22	Ltr. Oil							Oil	1,044	140,603	6,165	43,639	#N/A	41.80
23		2,734.8	1,091,670	59.4	73.1	81.3	9,248				10,024,470	24,478,899	2.24	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	50,740	87.4	99.3	88.1	10,642	Coal	22,657	11,917	539,999	950,331	1.87	41.94
4	4							Gas - G						
5	Crist 5	80.0	50,720	85.2	98.3	86.7	10,566	Coal	22,486	11,917	535,928	943,166	1.86	41.94
6	5							Gas - G						
7	Crist 6	302.0	123,530	55.0	62.6	87.8	10,224	Coal	52,992	11,917	1,263,002	2,222,727	1.80	41.94
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,909	8,770	1,524,461	2,608,068	1.75	30.01
12	Scholz 1	46.0	17,900	52.3	85.6	61.1	12,784	Coal	9,301	12,301	228,825	610,640	3.41	65.65
13	Scholz 2	46.0	18,550	54.2	84.5	64.1	12,772	Coal	9,630	12,301	236,918	632,237	3.41	65.65
14	Smith 1	162.0	103,880	86.2	98.7	87.3	10,266	Coal	44,431	12,001	1,066,465	1,751,491	1.69	39.42
15	Smith 2	189.0	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
16	Smith 3	531.0	241,320	61.1	88.4	69.1	7,233	Gas - G	1,694,671	1,030	1,745,511	12,204,542	5.06	7.20
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,390	97.0	96.9	100.1	9,928	Coal	87,767	10,486	1,840,573	3,164,193	1.71	36.05
20	Daniel 2 (1)	257.0	23,770	12.4	12.5	99.5	9,629	Coal	10,915	10,486	228,882	393,477	1.66	36.05
21	Gas,BL							Gas	4,126	1,030	4,249	27,448	#N/A	6.65
22	Ltr. Oil							Oil	897	140,593	5,295	37,416	#N/A	41.73
23		2,734.8	973,170	47.8	59.7	80.1	9,559				9,220,108	25,783,230	2.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	47,230	84.1	99.4	84.6	10,686	Coal	21,119	11,949	504,695	856,871	1.81	40.57
4	4							Gas - G						
5	Crist 5	80.0	47,170	81.9	98.6	83.1	10,660	Coal	21,041	11,949	502,833	853,709	1.81	40.57
6	5							Gas - G						
7	Crist 6	302.0	141,430	65.0	78.0	83.4	10,280	Coal	60,839	11,949	1,453,915	2,468,454	1.75	40.57
8	6							Gas - G						
9	Crist 7	477.0	116,680	34.0	41.3	82.3	10,356	Coal	50,563	11,949	1,208,323	2,051,488	1.76	40.57
10	7							Gas - G						
11	Scherer 3 (2)	210.8	143,930	94.9	94.6	100.3	10,246	Coal	84,053	8,772	1,474,651	2,526,529	1.76	30.06
12	Scholz 1	46.0	16,350	49.4	84.8	58.2	10,631	Coal	7,126	12,195	173,816	487,590	2.98	68.42
13	Scholz 2	46.0	16,580	50.1	85.1	58.8	11,435	Coal	7,773	12,195	189,597	531,859	3.21	68.42
14	Smith 1	162.0	95,370	81.8	98.7	82.8	10,282	Coal	40,851	12,002	980,601	1,610,891	1.69	39.43
15	Smith 2	189.0	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
16	Smith 3	481.0	232,950	67.3	88.5	76.0	6,466	Gas - G	1,462,304	1,030	1,506,173	11,249,458	4.83	7.69
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	177,450	95.9	97.1	98.8	9,935	Coal	83,773	10,522	1,762,920	3,148,244	1.77	37.58
20	Daniel 2 (1)	257.0	160,020	86.5	87.5	98.8	9,894	Coal	75,235	10,522	1,583,258	2,827,401	1.77	37.58
21	Gas,BL							Gas	5,701	1,030	5,871	35,228	#N/A	6.18
22	Ltr. Oil							Oil	1,045	140,598	6,170	44,095	#N/A	42.20
23		2,676.8	1,203,460	62.4	75.4	82.8	9,499				11,352,823	28,921,561	2.40	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,870	80.8	99.5	81.2	10,639	Coal	20,948	11,902	498,647	909,406	1.94	43.41
4	4							Gas - G						
5	Crist 5	80.0	46,470	78.1	98.5	79.3	10,779	Coal	21,042	11,902	500,895	913,506	1.97	43.41
6	5							Gas - G						
7	Crist 6	302.0	170,130	75.7	97.4	77.7	10,376	Coal	74,157	11,902	1,765,236	3,219,346	1.89	43.41
8	6							Gas - G						
9	Crist 7	477.0	272,660	76.8	95.2	80.7	10,373	Coal	118,815	11,902	2,828,301	5,158,110	1.89	43.41
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,870	95.6	95.7	99.9	10,239	Coal	87,452	8,773	1,534,486	2,631,446	1.76	30.09
12	Scholz 1	46.0	15,690	45.8	88.2	52.0	12,508	Coal	8,091	12,129	196,253	567,714	3.62	70.17
13	Scholz 2	46.0	16,140	47.2	87.8	53.7	12,733	Coal	8,472	12,128	205,510	594,492	3.68	70.17
14	Smith 1	162.0	93,220	77.3	98.7	78.4	10,304	Coal	40,012	12,003	960,544	1,578,448	1.69	39.45
15	Smith 2	189.0	98,970	70.4	91.4	77.0	10,361	Coal	42,716	12,003	1,025,476	1,685,150	1.70	39.45
16	Smith 3	481.0	208,120	58.2	93.8	62.0	7,088	Gas - G	1,432,111	1,030	1,475,075	11,946,049	5.74	8.34
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	174,410	91.2	97.2	93.8	9,975	Coal	83,051	10,474	1,739,763	3,168,634	1.82	38.15
20	Daniel 2 (1)	257.0	176,910	92.5	97.3	95.1	9,813	Coal	82,874	10,474	1,736,054	3,161,878	1.79	38.15
21	Gas,BL							Gas	5,701	1,030	5,871	38,692	#N/A	6.79
22	Ltr. Oil							Oil	1,192	140,606	7,040	50,979	#N/A	42.76
23		2,676.8	1,478,040	74.2	95.7	77.5	9,853				14,479,151	35,861,344	2.43	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,290	82.4	99.4	82.9	10,595	Coal	20,648	11,876	490,455	944,315	2.04	45.73
4	4							Gas - G						
5	Crist 5	80.0	46,270	80.3	98.6	81.5	10,710	Coal	20,863	11,876	495,552	954,128	2.06	45.73
6	5							Gas - G						
7	Crist 6	302.0	169,170	77.8	97.5	79.8	10,339	Coal	73,634	11,876	1,749,003	3,367,505	1.99	45.73
8	6							Gas - G						
9	Crist 7	477.0	269,200	78.4	95.1	82.4	10,356	Coal	117,369	11,876	2,787,844	5,367,673	1.99	45.73
10	7							Gas - G						
11	Scherer 3 (2)	210.8	145,830	96.1	95.7	100.4	10,243	Coal	85,128	8,773	1,493,725	2,562,132	1.76	30.10
12	Scholz 1	46.0	19,160	57.9	87.5	66.1	12,126	Coal	9,612	12,085	232,332	685,312	3.58	71.30
13	Scholz 2	46.0	18,010	54.4	88.2	61.7	12,329	Coal	9,186	12,085	222,040	654,954	3.64	71.30
14	Smith 1	162.0	91,830	78.7	98.8	79.7	10,297	Coal	39,387	12,004	945,597	1,554,189	1.69	39.46
15	Smith 2	189.0	101,630	74.7	94.4	79.1	10,374	Coal	43,914	12,004	1,054,296	1,732,847	1.71	39.46
16	Smith 3	481.0	246,310	71.1	93.9	75.7	7,124	Gas - G	1,703,548	1,030	1,754,654	13,808,048	5.61	8.11
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	176,860	95.6	97.1	98.4	9,938	Coal	84,225	10,434	1,757,667	3,302,000	1.87	39.20
20	Daniel 2 (1)	257.0	178,190	96.3	97.2	99.1	9,781	Coal	83,517	10,434	1,742,889	3,274,239	1.84	39.20
21	Gas,BL							Gas	5,701	1,030	5,871	38,692	#N/A	6.79
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,248	#N/A	42.99
23		2,676.8	1,517,050	78.7	95.9	82.1	9,769				14,738,965	38,527,026	2.54	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	99.3	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	49,890	86.0	99.5	86.4	10,522	Coal	22,154	11,847	524,933	1,066,671	2.14	48.15
4	4							Gas - G						
5	Crist 5	80.0	49,970	84.0	98.5	85.2	10,388	Coal	21,909	11,847	519,111	1,054,842	2.11	48.15
6	5							Gas - G						
7	Crist 6	302.0	186,290	82.9	97.4	85.1	10,509	Coal	82,624	11,847	1,957,706	3,978,088	2.14	48.15
8	6							Gas - G						
9	Crist 7	477.0	295,160	83.2	95.2	87.4	10,410	Coal	129,679	11,847	3,072,650	6,243,671	2.12	48.15
10	7							Gas - G						
11	Scherer 3 (2)	210.8	150,690	96.1	95.7	100.4	10,245	Coal	87,980	8,773	1,543,767	2,648,283	1.76	30.10
12	Scholz 1	46.0	21,650	63.3	87.6	72.2	12,063	Coal	10,833	12,055	261,171	781,310	3.61	72.12
13	Scholz 2	46.0	20,820	60.8	87.8	69.3	12,454	Coal	10,755	12,054	259,290	775,682	3.73	72.12
14	Smith 1	162.0	101,250	84.0	98.7	85.1	10,273	Coal	43,323	12,004	1,040,142	1,712,140	1.69	39.52
15	Smith 2	189.0	112,800	80.2	94.5	84.9	10,204	Coal	47,940	12,004	1,150,979	1,894,583	1.68	39.52
16	Smith 3	481.0	301,250	84.2	93.8	89.7	7,021	Gas - G	2,053,572	1,030	2,115,179	16,780,243	5.57	8.17
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,360	96.9	97.2	99.7	9,928	Coal	88,088	10,446	1,840,208	3,495,697	1.89	39.68
20	Daniel 2 (1)	257.0	185,670	97.1	97.3	99.8	9,776	Coal	86,887	10,446	1,815,134	3,448,065	1.86	39.68
21	Gas,BL							Gas	5,701	1,030	5,871	40,277	#N/A	7.06
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,487	#N/A	43.19
23		2,676.8	1,669,380	83.8	95.9	87.4	9,702				16,113,181	44,208,533	2.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	400	2.2	98.9	2.3	16,488	Gas - G	6,403	1,030	6,595	45,306	11.33	7.08
2	Crist 3	35.0	780	3.0	100.0	3.0	14,505	Gas - G	10,984	1,030	11,314	77,726	9.96	7.08
3	Crist 4	78.0	50,220	86.5	99.5	87.0	10,509	Coal	22,307	11,830	527,779	1,104,701	2.20	49.52
4	4							Gas - G						
5	Crist 5	80.0	50,240	84.4	98.5	85.7	10,329	Coal	21,933	11,830	518,932	1,086,184	2.16	49.52
6	5							Gas - G						
7	Crist 6	302.0	187,830	83.6	97.4	85.8	10,521	Coal	83,525	11,830	1,976,192	4,136,394	2.20	49.52
8	6							Gas - G						
9	Crist 7	477.0	297,220	83.8	95.2	88.0	10,304	Coal	129,441	11,830	3,062,576	6,410,318	2.16	49.52
10	7							Gas - G						
11	Scherer 3 (2)	210.8	150,690	96.1	95.7	100.4	10,245	Coal	87,980	8,773	1,543,767	2,648,510	1.76	30.10
12	Scholz 1	46.0	21,210	62.0	87.6	70.7	11,482	Coal	10,118	12,035	243,526	735,123	3.47	72.65
13	Scholz 2	46.0	20,580	60.1	88.0	68.3	12,489	Coal	10,679	12,035	257,025	775,873	3.77	72.65
14	Smith 1	162.0	102,380	84.9	98.7	86.1	10,269	Coal	43,789	12,005	1,051,331	1,732,076	1.69	39.56
15	Smith 2	189.0	113,980	81.1	94.5	85.8	10,200	Coal	48,425	12,005	1,162,641	1,915,460	1.68	39.56
16	Smith 3	481.0	302,390	84.5	93.8	90.1	7,167	Gas - G	2,103,980	1,030	2,167,099	17,140,051	5.67	8.15
17	Smith A (CT)	32.0	220	0.9	100.0	0.9	14,323	Oil - G	534	140,621	3,151	22,145	10.07	41.51
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,230	96.9	97.2	99.7	9,929	Coal	88,154	10,432	1,839,169	3,537,553	1.91	40.13
20	Daniel 2 (1)	257.0	185,580	97.1	97.3	99.7	9,777	Coal	86,967	10,432	1,814,392	3,489,895	1.88	40.13
21	Gas,BL							Gas	5,701	1,030	5,871	40,335	#N/A	7.08
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,699	#N/A	43.37
23		2,676.8	1,677,530	84.2	95.9	87.8	9,706				16,198,400	45,186,843	2.69	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	290	1.7	98.9	1.7	17,940	Gas - G	5,051	1,030	5,203	32,569	11.23	6.45
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	47,150	84.0	99.4	84.5	10,559	Coal	21,080	11,809	497,877	1,052,168	2.23	49.91
4	4							Gas - G						
5	Crist 5	80.0	47,340	82.2	98.6	83.4	10,443	Coal	20,932	11,809	494,386	1,044,790	2.21	49.91
6	5							Gas - G						
7	Crist 6	302.0	51,700	23.8	29.3	81.1	10,318	Coal	22,585	11,809	533,431	1,127,305	2.18	49.91
8	6							Gas - G						
9	Crist 7	477.0	272,950	79.5	95.1	83.6	10,473	Coal	121,031	11,809	2,858,596	6,041,098	2.21	49.91
10	7							Gas - G						
11	Scherer 3 (2)	210.8	145,830	96.1	95.7	100.4	10,237	Coal	85,076	8,774	1,492,887	2,561,843	1.76	30.11
12	Scholz 1	46.0	17,430	52.6	88.6	59.4	11,817	Coal	8,565	12,023	205,963	624,997	3.59	72.97
13	Scholz 2	46.0	17,530	52.9	88.8	59.6	12,286	Coal	8,957	12,023	215,376	653,560	3.73	72.97
14	Smith 1	162.0	93,930	80.5	98.8	81.5	10,288	Coal	40,248	12,005	966,345	1,592,833	1.70	39.58
15	Smith 2	189.0	104,700	76.9	94.4	81.5	10,220	Coal	44,567	12,005	1,070,030	1,763,738	1.68	39.57
16	Smith 3	481.0	250,450	72.3	93.9	77.0	7,105	Gas - G	1,727,511	1,030	1,779,336	13,385,249	5.34	7.75
17	Smith A (CT	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	136,680	73.9	74.4	99.3	9,932	Coal	65,211	10,408	1,357,483	2,626,827	1.92	40.28
20	Daniel 2 (1)	257.0	179,170	96.8	97.2	99.6	9,777	Coal	84,149	10,408	1,751,711	3,389,685	1.89	40.28
21	Gas,BL							Gas	5,701	1,030	5,871	36,754	#N/A	6.45
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,889	#N/A	43.53
23		2,676.8	1,373,450	71.3	86.1	82.8	9,700				13,241,535	36,215,049	2.64	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	49,280	84.9	99.2	85.6	10,544	Coal	22,071	11,771	519,592	1,098,670	2.23	49.78
4	4							Gas - G						
5	Crist 5	80.0	49,350	82.9	98.4	84.3	10,360	Coal	21,718	11,771	511,265	1,081,064	2.19	49.78
6	5							Gas - G						
7	Crist 6	302.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
8	6							Gas - G						
9	Crist 7	477.0	239,040	67.4	79.5	84.7	10,224	Coal	103,816	11,771	2,443,978	5,167,762	2.16	49.78
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,870	8,774	1,524,461	2,616,667	1.76	30.12
12	Scholz 1	46.0	15,960	46.6	86.8	53.7	13,590	Coal	9,027	12,014	216,894	661,006	4.14	73.23
13	Scholz 2	46.0	16,170	47.2	86.2	54.8	13,221	Coal	8,897	12,014	213,784	651,527	4.03	73.23
14	Smith 1	162.0	66,610	55.3	66.7	82.9	10,283	Coal	28,527	12,005	684,928	1,130,709	1.70	39.64
15	Smith 2	189.0	102,560	72.9	88.3	82.6	10,215	Coal	43,636	12,005	1,047,696	1,729,582	1.69	39.64
16	Smith 3	481.0	263,220	73.6	88.5	83.1	7,463	Gas - G	1,907,266	1,030	1,964,484	14,557,234	5.53	7.63
17	Smith A (CT	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
20	Daniel 2 (1)	257.0	173,000	90.5	91.0	99.4	9,780	Coal	81,728	10,351	1,691,933	3,198,044	1.85	39.13
21	Gas,BL							Gas	2,848	1,030	2,933	18,361	#N/A	6.45
22	Ltr. Oil							Oil	1,020	140,613	6,025	45,042	#N/A	44.15
23		2,676.8	1,132,560	56.9	68.7	82.8	9,634				10,827,973	32,193,162	2.84	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,960	83.6	99.3	84.2	10,567	Coal	21,123	11,746	496,226	1,049,270	2.23	49.67
4	4							Gas - G						
5	Crist 5	80.0	46,770	81.2	98.6	82.4	10,137	Coal	20,181	11,746	474,094	1,002,472	2.14	49.67
6	5							Gas - G						
7	Crist 6	302.0	54,180	24.9	32.2	77.4	10,396	Coal	23,976	11,746	563,248	1,190,987	2.20	49.67
8	6							Gas - G						
9	Crist 7	477.0	192,620	56.1	66.3	84.6	10,337	Coal	84,756	11,746	1,991,085	4,210,147	2.19	49.67
10	7							Gas - G						
11	Scherer 3 (2)	210.8	143,870	94.8	94.6	100.2	10,250	Coal	84,033	8,774	1,474,651	2,531,067	1.76	30.12
12	Scholz 1	46.0	15,640	47.2	86.3	54.7	12,614	Coal	8,213	12,009	197,276	602,580	3.85	73.37
13	Scholz 2	46.0	10,110	30.5	73.6	41.5	14,218	Coal	5,985	12,009	143,740	439,055	4.34	73.36
14	Smith 1	162.0	25,610	22.0	26.4	83.2	10,281	Coal	10,967	12,005	263,304	435,033	1.70	39.67
15	Smith 2	189.0	105,250	77.3	94.2	82.1	10,218	Coal	44,793	12,005	1,075,474	1,776,907	1.69	39.67
16	Smith 3	531.0	189,940	49.7	82.5	60.2	5,869	Gas - G	1,082,229	1,030	1,114,696	7,862,381	4.14	7.26
17	Smith A (CT)	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	28,760	15.5	16.3	95.4	9,959	Coal	13,727	10,433	286,422	536,740	1.87	39.10
20	Daniel 2 (1)	257.0	178,570	96.5	96.9	99.6	9,780	Coal	83,700	10,433	1,746,417	3,272,694	1.83	39.10
21	Gas,BL							Gas	5,701	1,030	5,871	36,813	#N/A	6.46
22	Ltr. Oil							Oil	1,192	140,606	7,040	52,155	#N/A	43.75
23		2,734.8	1,046,580	53.2	69.2	76.8	9,477				9,839,544	25,228,045	2.41	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	41,750	71.9	93.0	77.4	10,751	Coal	19,066	11,771	448,845	914,179	2.19	47.95
4	4							Gas - G						
5	Crist 5	80.0	42,990	72.2	98.5	73.3	10,986	Coal	20,062	11,771	472,296	961,944	2.24	47.95
6	5							Gas - G						
7	Crist 6	302.0	149,510	66.5	88.0	75.6	10,416	Coal	66,149	11,771	1,557,265	3,171,743	2.12	47.95
8	6							Gas - G						
9	Crist 7	477.0	271,530	76.5	95.2	80.4	10,377	Coal	119,686	11,771	2,817,620	5,738,757	2.11	47.95
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,868	8,775	1,524,461	2,616,960	1.76	30.13
12	Scholz 1	46.0	8,760	25.6	89.7	28.5	13,365	Coal	4,875	12,008	117,081	357,863	4.09	73.41
13	Scholz 2	46.0	0	0.0	19.4	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
14	Smith 1	162.0	91,470	75.9	98.7	76.9	10,313	Coal	39,289	12,005	943,332	1,559,709	1.71	39.70
15	Smith 2	189.0	92,510	65.8	85.3	77.1	10,245	Coal	39,476	12,005	947,804	1,567,102	1.69	39.70
16	Smith 3	531.0	25,390	6.4	37.1	17.3	8,422	Gas - G	207,615	1,030	213,843	2,303,258	9.07	11.09
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,497	2.77	#N/A
19	Daniel 1 (1)	257.0	185,010	96.8	97.2	99.5	9,930	Coal	87,966	10,442	1,837,170	3,486,732	1.88	39.64
20	Daniel 2 (1)	257.0	185,570	97.1	97.0	100.1	9,777	Coal	86,870	10,442	1,814,293	3,443,315	1.86	39.64
21	Gas,BL							Gas	5,701	1,030	5,871	40,628	#N/A	7.13
22	Ltr. Oil							Oil	1,172	140,605	6,921	51,401	#N/A	43.86
23		2,734.8	1,251,860	61.5	81.8	75.2	10,220				12,706,802	26,451,088	2.11	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2005 - DECEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	690	0.3	99.8	0.3	17,099	Gas - G	11,454	1,030	11,798	77,874	11.29	6.80
2	Crist 3	35.0	780	0.3	99.9	0.3	14,505	Gas - G	10,984	1,030	11,314	77,726	9.96	7.08
3	Crist 4	78.0	570,290	83.5	98.9	84.4	10,610	Coal	255,412	11,845	6,050,921	11,826,018	2.07	46.30
4	4							Gas - G						
5	Crist 5	80.0	560,690	80.0	96.9	82.6	10,548	Coal	249,643	11,845	5,914,200	11,562,847	2.06	46.32
6	5							Gas - G						
7	Crist 6	302.0	1,588,420	60.0	72.9	82.4	10,416	Coal	697,551	11,859	16,544,454	31,873,198	2.01	45.69
8	6							Gas - G						
9	Crist 7	477.0	2,493,660	59.7	70.8	84.3	10,340	Coal	1,089,821	11,830	25,785,180	51,613,596	2.07	47.36
10	7							Gas - G						
11	Scherer 3 (2)	210.8	1,760,290	95.3	95.0	100.4	10,244	Coal	1,027,907	8,772	18,032,790	30,885,672	1.75	30.05
12	Scholz 1	46.0	196,230	48.7	87.3	55.8	12,130	Coal	97,912	12,155	2,380,223	6,805,900	3.47	69.51
13	Scholz 2	46.0	182,270	45.2	80.0	56.5	12,385	Coal	92,764	12,168	2,257,473	6,416,384	3.52	69.17
14	Smith 1	162.0	1,061,330	74.8	90.0	83.1	10,274	Coal	454,210	12,003	10,903,657	17,947,978	1.69	39.51
15	Smith 2	189.0	981,200	59.3	72.2	82.1	10,211	Coal	417,315	12,004	10,018,589	16,506,003	1.68	39.55
16	Smith 3	502.0	2,607,900	59.3	85.9	69.0	6,965	Gas - G	17,634,767	1,030	18,163,809	139,369,513	5.34	7.90
17	Smith A (CT)	35.0	220	0.1	100.0	0.1	14,323	Oil - G	534	140,621	3,151	22,145	10.07	41.51
18	Other Generation		101,010									2,795,957	2.77	#N/A
19	Daniel 1 (1)	257.0	1,757,220	78.1	79.0	98.8	9,953	Coal	836,600	10,453	17,489,770	32,000,224	1.82	38.25
20	Daniel 2 (1)	257.0	1,967,470	87.4	88.2	99.1	9,742	Coal	918,185	10,437	19,166,286	35,452,663	1.80	38.61
21	Gas,BL							Gas	62,409	1,030	64,270	424,440	#N/A	6.80
22	Ltr. Oil							Oil	13,523	140,605	79,856	580,586	#N/A	42.93
23		2,700.8	15,829,670	66.9	82.5	81.1	9,720				152,877,741	396,238,725	2.50	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
3	UNIT COST ($/BBL)	44.78	44.85	44.89	44.81	44.78	44.78	44.78	44.78	44.78	44.87	44.78	44.79	44.80
4	AMOUNT ($)	53,382	46,819	40,252	46,815	53,382	53,382	53,382	53,382	53,382	45,774	53,382	52,487	605,821
5	*BURNED :*													
6	UNITS (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
7	UNIT COST ($/BBL)	41.55	41.80	41.73	42.20	42.76	42.99	43.19	43.37	43.53	44.15	43.75	43.86	42.93
8	AMOUNT ($)	49,536	43,639	37,416	44,095	50,979	51,248	51,487	51,699	51,889	45,042	52,155	51,401	580,586
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	
11	UNIT COST ($/BBL)	40.71	41.09	41.43	41.76	42.04	42.30	42.53	42.73	42.90	42.99	43.14	43.27	
12	AMOUNT ($)	340,689	343,869	346,705	349,425	351,828	353,962	355,857	357,540	359,033	359,765	360,992	362,078	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	511,247	353,296	268,186	382,424	515,144	502,652	542,524	543,984	436,325	320,795	318,124	482,137	5,176,838
16	UNIT COST ($/TON)	40.81	38.63	40.52	40.62	43.96	45.37	46.34	46.57	45.79	45.15	45.26	43.25	43.76
17	AMOUNT ($)	20,865,697	13,647,161	10,866,576	15,535,546	22,647,855	22,804,019	25,140,258	25,334,687	19,979,038	14,484,179	14,398,540	20,851,253	226,554,809
18	*BURNED :*													
19	UNITS (TONS)	497,555	333,691	260,179	368,320	500,178	502,355	544,192	545,338	437,325	319,420	317,421	483,439	5,109,413
20	UNIT COST ($/TON)	41.54	39.89	41.00	40.28	41.90	43.47	44.93	45.70	45.54	46.08	45.73	43.86	43.45
21	AMOUNT ($)	20,669,919	13,309,357	10,668,262	14,836,507	20,956,684	21,837,162	24,450,749	24,923,577	19,917,001	14,718,364	14,515,885	21,201,344	222,004,811
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	543,703	563,308	571,315	585,419	600,385	600,682	599,014	597,660	596,660	598,035	598,738	597,436	
24	UNIT COST ($/TON)	43.22	42.32	42.07	42.25	44.02	45.60	46.88	47.68	47.86	47.36	47.11	46.62	
25	AMOUNT ($)	23,500,205	23,838,009	24,036,323	24,735,362	26,426,533	27,393,390	28,082,899	28,494,009	28,556,046	28,321,861	28,204,516	27,854,425	
26	DAYS SUPPLY:	28	29	29	30	31	31	31	31	31	31	31	31	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	1,253,653	1,330,734	1,624,279	1,490,235	1,522,138	1,439,003	1,433,745	1,437,425	1,489,863	1,521,235	1,471,514	1,521,234	17,535,059
29	UNIT COST ($/MMBTU	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72
30	AMOUNT ($)	2,147,208	2,281,069	2,790,854	2,558,067	2,613,470	2,469,095	2,459,964	2,466,354	2,557,421	2,611,902	2,525,555	2,611,902	30,092,862
31	*BURNED :*													
32	UNITS (MMBTU)	1,524,461	1,377,012	1,524,461	1,474,651	1,534,486	1,493,725	1,543,767	1,543,767	1,492,887	1,524,461	1,474,651	1,524,461	18,032,790
33	UNIT COST ($/MMBTU	1.70	1.70	1.71	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.71
34	AMOUNT ($)	2,587,366	2,346,801	2,608,068	2,526,529	2,631,446	2,562,132	2,648,283	2,648,510	2,561,843	2,616,667	2,531,067	2,616,960	30,885,672
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	2,063,323	2,017,045	2,116,863	2,132,447	2,120,099	2,065,377	1,955,355	1,849,013	1,845,990	1,842,763	1,839,627	1,836,400	
37	UNIT COST ($/MMBTU	1.70	1.71	1.71	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	
38	AMOUNT ($)	3,505,099	3,439,368	3,622,155	3,653,693	3,635,717	3,542,680	3,354,361	3,172,205	3,167,783	3,163,019	3,157,507	3,152,449	
39	DAYS SUPPLY:	40	39	41	41	41	40	38	36	36	35	35	35	
	GAS													
44	*BURNED :*													
45	UNITS (MCF)	1,202,853	1,066,934	1,698,797	1,468,005	1,437,812	1,709,249	2,059,273	2,127,068	1,738,263	1,910,114	1,087,930	213,316	17,719,614
46	UNIT COST ($/MCF)	8.01	8.03	7.20	7.69	8.34	8.10	8.17	8.13	7.74	7.63	7.26	10.99	7.90
47	AMOUNT ($)	9,639,630	8,564,582	12,231,990	11,284,686	11,984,741	13,846,740	16,820,520	17,303,418	13,454,572	14,575,595	7,899,194	2,343,886	139,949,554
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
55	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	44.55	#N/A	#N/A	#N/A	#N/A	44.55
56	AMOUNT ($)	0	0	0	0	0	0	0	23,789	0	0	0	0	23,789
57	*BURNED :*													
58	UNITS (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
59	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	41.47	#N/A	#N/A	#N/A	#N/A	41.47
60	AMOUNT ($)	0	0	0	0	0	0	0	22,145	0	0	0	0	22,145
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	
63	UNIT COST ($/BBL)	41.38	41.38	41.38	41.38	41.38	41.38	41.38	41.51	41.51	41.51	41.51	41.51	
64	AMOUNT ($)	532,049	532,049	532,049	532,049	532,049	532,049	532,049	533,693	533,693	533,693	533,693	533,693	
65	DAYS SUPPLY:	7	7	7	7	7	7	7	7	7	7	7	7	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
			KWH		¢ / KWH		TOTAL $	
	MONTH	TOTAL	WHEELED	KWH	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	COST	COST	ADJUSTMENT	$
	JANUARY							
1	Southern Co. Interchange	375,877,000	0	375,877,000	3.07	3.31	11,546,000	12,440,000
2	Unit Power Sales	108,739,000	0	108,739,000	1.84	1.98	2,003,000	2,151,000
3	Economy Sales	7,638,000	0	7,638,000	3.71	3.77	283,000	288,000
4	Gain on Economy Sales						279,000	279,000
5	TOTAL ESTIMATED SALES	492,254,000	0	492,254,000	2.87	3.08	14,111,000	15,158,000
	FEBRUARY							
1	Southern Co. Interchange	160,664,000	0	160,664,000	3.09	3.35	4,972,000	5,376,000
2	Unit Power Sales	133,090,000	0	133,090,000	2.01	2.13	2,678,000	2,841,000
3	Economy Sales	4,068,000	0	4,068,000	4.25	4.13	173,000	168,000
4	Gain on Economy Sales						234,000	234,000
5	TOTAL ESTIMATED SALES	297,822,000	0	297,822,000	2.71	2.89	8,057,000	8,619,000
	MARCH							
1	Southern Co. Interchange	77,571,000	0	77,571,000	3.36	3.60	2,606,000	2,791,000
2	Unit Power Sales	157,535,000	0	157,535,000	2.00	2.13	3,155,000	3,348,000
3	Economy Sales	8,542,000	0	8,542,000	4.13	4.13	353,000	353,000
4	Gain on Economy Sales						197,000	197,000
5	TOTAL ESTIMATED SALES	243,648,000	0	243,648,000	2.59	2.75	6,311,000	6,689,000
	APRIL							
1	Southern Co. Interchange	256,070,000	0	256,070,000	3.15	3.39	8,058,000	8,676,000
2	Unit Power Sales	108,451,000	0	108,451,000	1.85	1.99	2,011,000	2,162,000
3	Economy Sales	4,691,000	0	4,691,000	3.88	3.94	182,000	185,000
4	Gain on Economy Sales						164,000	164,000
5	TOTAL ESTIMATED SALES	369,212,000	0	369,212,000	2.82	3.03	10,415,000	11,187,000
	MAY							
1	Southern Co. Interchange	296,843,000	0	296,843,000	3.07	3.30	9,103,000	9,808,000
2	Unit Power Sales	107,463,000	0	107,463,000	1.82	1.96	1,958,000	2,106,000
3	Economy Sales	4,909,000	0	4,909,000	3.63	3.71	178,000	182,000
4	Gain on Economy Sales						225,000	225,000
5	TOTAL ESTIMATED SALES	409,215,000	0	409,215,000	2.80	3.01	11,464,000	12,321,000
	JUNE							
1	Southern Co. Interchange	192,906,000	0	192,906,000	3.39	3.62	6,535,000	6,988,000
2	Unit Power Sales	126,356,000	0	126,356,000	1.82	1.96	2,302,000	2,478,000
3	Economy Sales	8,828,000	0	8,828,000	3.89	3.94	343,000	348,000
4	Gain on Economy Sales						289,000	289,000
5	TOTAL ESTIMATED SALES	328,090,000	0	328,090,000	2.89	3.08	9,469,000	10,103,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
	MONTH	TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JULY							
1	Southern Co. Interchange	260,376,000	0	260,376,000	3.67	3.91	9,554,000	10,181,000
2	Unit Power Sales	127,569,000	0	127,569,000	1.85	1.98	2,356,000	2,532,000
3	Economy Sales	8,463,000	0	8,463,000	4.82	4.84	408,000	410,000
4	Gain on Economy Sales						312,000	312,000
5	TOTAL ESTIMATED SALES	396,408,000	0	396,408,000	3.19	3.39	12,630,000	13,435,000
	AUGUST							
1	Southern Co. Interchange	282,011,000	0	282,011,000	3.91	4.15	11,033,000	11,695,000
2	Unit Power Sales	127,879,000	0	127,879,000	1.85	1.99	2,371,000	2,546,000
3	Economy Sales	4,590,000	0	4,590,000	5.29	5.34	243,000	245,000
4	Gain on Economy Sales						271,000	271,000
5	TOTAL ESTIMATED SALES	414,480,000	0	414,480,000	3.36	3.56	13,918,000	14,757,000
	SEPTEMBER							
1	Southern Co. Interchange	242,762,000	0	242,762,000	3.27	3.51	7,948,000	8,523,000
2	Unit Power Sales	105,510,000	0	105,510,000	1.83	1.97	1,930,000	2,076,000
3	Economy Sales	7,125,000	0	7,125,000	4.08	4.14	291,000	295,000
4	Gain on Economy Sales						79,000	79,000
5	TOTAL ESTIMATED SALES	355,397,000	0	355,397,000	2.88	3.09	10,248,000	10,973,000
	OCTOBER							
1	Southern Co. Interchange	167,937,000	0	167,937,000	3.28	3.54	5,501,000	5,942,000
2	Unit Power Sales	91,028,000	0	91,028,000	1.87	2.00	1,699,000	1,825,000
3	Economy Sales	4,359,000	0	4,359,000	3.83	3.88	167,000	169,000
4	Gain on Economy Sales						93,000	93,000
5	TOTAL ESTIMATED SALES	263,324,000	0	263,324,000	2.83	3.05	7,460,000	8,029,000
	NOVEMBER							
1	Southern Co. Interchange	190,487,000	0	190,487,000	3.10	3.36	5,896,000	6,399,000
2	Unit Power Sales	98,578,000	0	98,578,000	1.85	1.99	1,827,000	1,964,000
3	Economy Sales	5,749,000	0	5,749,000	3.79	3.83	218,000	220,000
4	Gain on Economy Sales						248,000	248,000
5	TOTAL ESTIMATED SALES	294,814,000	0	294,814,000	2.78	3.00	8,189,000	8,831,000
	DECEMBER							
1	Southern Co. Interchange	239,647,000	0	239,647,000	2.86	3.08	6,844,000	7,380,000
2	Unit Power Sales	112,171,000	0	112,171,000	1.82	1.96	2,037,000	2,193,000
3	Economy Sales	4,700,000	0	4,700,000	3.28	3.38	154,000	159,000
4	Gain on Economy Sales						236,000	236,000
5	TOTAL ESTIMATED SALES	356,518,000	0	356,518,000	2.60	2.80	9,271,000	9,968,000
	TOTAL							
1	Southern Co. Interchange	2,743,151,000	0	2,743,151,000	3.27	3.51	89,596,000	96,199,000
2	Unit Power Sales	1,404,369,000	0	1,404,369,000	1.87	2.01	26,327,000	28,222,000
3	Economy Sales	73,662,000	0	73,662,000	4.06	4.10	2,993,000	3,022,000
4	Gain on Economy Sales						2,627,000	2,627,000
5	TOTAL ESTIMATED SALES	4,221,182,000	0	4,221,182,000	2.88	3.08	121,543,000	130,070,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							¢ / KWH		
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				None			
FEBRUARY	Solutia	COG-1				None			
MARCH	Solutia	COG-1				None			
APRIL	Solutia	COG-1				None			
MAY	Solutia	COG-1				None			
JUNE	Solutia	COG-1				None			
JULY	Solutia	COG-1				None			
AUGUST	Solutia	COG-1				None			
SEPTEMBER	Solutia	COG-1				None			
OCTOBER	Solutia	COG-1				None			
NOVEMBER	Solutia	COG-1				None			
DECEMBER	Solutia	COG-1				None			
TOTAL			0			-			0

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	11,206,000	2.97	333,000
2	Unit Power Sales	1,078,000	3.71	40,000
3	Economy Energy	3,045,000	3.71	113,000
4	Other Purchases	4,220,000	2.80	118,000
5	TOTAL ESTIMATED PURCHASES	19,549,000	3.09	604,000
	FEBRUARY			
1	Southern Co. Interchange	20,008,000	3.53	707,000
2	Unit Power Sales	4,138,000	3.79	157,000
3	Economy Energy	2,100,000	4.00	84,000
4	Other Purchases	8,620,000	2.98	257,000
5	TOTAL ESTIMATED PURCHASES	34,866,000	3.46	1,205,000
	MARCH			
1	Southern Co. Interchange	103,471,000	3.35	3,467,000
2	Unit Power Sales	4,212,000	3.70	156,000
3	Economy Energy	3,348,000	4.06	136,000
4	Other Purchases	15,900,000	3.34	531,000
5	TOTAL ESTIMATED PURCHASES	126,931,000	3.38	4,290,000
	APRIL			
1	Southern Co. Interchange	8,421,000	3.50	295,000
2	Unit Power Sales	1,550,000	3.55	55,000
3	Economy Energy	1,995,000	3.76	75,000
4	Other Purchases	17,960,000	3.76	561,000
5	TOTAL ESTIMATED PURCHASES	29,926,000	3.29	986,000
	MAY			
1	Southern Co. Interchange	12,146,000	2.96	360,000
2	Unit Power Sales	1,517,000	3.36	51,000
3	Economy Energy	2,445,000	3.56	87,000
4	Other Purchases	19,690,000	2.88	567,000
5	TOTAL ESTIMATED PURCHASES	35,798,000	2.98	1,065,000
	JUNE			
1	Southern Co. Interchange	20,267,000	3.90	790,000
2	Unit Power Sales	2,051,000	3.71	76,000
3	Economy Energy	4,622,000	3.72	172,000
4	Other Purchases	15,350,000	3.39	521,000
5	TOTAL ESTIMATED PURCHASES	42,290,000	3.69	1,559,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	16,755,000	5.63	944,000
2	Unit Power Sales	2,334,000	4.97	116,000
3	Economy Energy	4,960,000	4.90	243,000
4	Other Purchases	8,050,000	3.78	304,000
5	TOTAL ESTIMATED PURCHASES	32,099,000	5.01	1,607,000
	AUGUST			
1	Southern Co. Interchange	8,424,000	4.25	358,000
2	Unit Power Sales	2,292,000	5.19	119,000
3	Economy Energy	3,049,000	5.41	165,000
4	Other Purchases	7,990,000	3.89	311,000
5	TOTAL ESTIMATED PURCHASES	21,755,000	4.38	953,000
	SEPTEMBER			
1	Southern Co. Interchange	26,217,000	4.49	1,178,000
2	Unit Power Sales	1,598,000	3.63	58,000
3	Economy Energy	4,602,000	4.06	187,000
4	Other Purchases	8,440,000	3.23	273,000
5	TOTAL ESTIMATED PURCHASES	40,857,000	4.15	1,696,000
	OCTOBER			
1	Southern Co. Interchange	47,636,000	3.23	1,540,000
2	Unit Power Sales	1,314,000	3.73	49,000
3	Economy Energy	2,530,000	3.75	95,000
4	Other Purchases	10,320,000	2.76	285,000
5	TOTAL ESTIMATED PURCHASES	61,800,000	3.19	1,969,000
	NOVEMBER			
1	Southern Co. Interchange	52,081,000	3.40	1,771,000
2	Unit Power Sales	1,541,000	3.83	59,000
3	Economy Energy	2,096,000	3.67	77,000
4	Other Purchases	9,720,000	2.80	272,000
5	TOTAL ESTIMATED PURCHASES	65,438,000	3.33	2,179,000
	DECEMBER			
1	Southern Co. Interchange	11,480,000	2.79	320,000
2	Unit Power Sales	1,078,000	3.25	35,000
3	Economy Energy	2,089,000	3.30	69,000
4	Other Purchases	10,380,000	2.57	267,000
5	TOTAL ESTIMATED PURCHASES	25,027,000	2.76	691,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	338,112,000	3.57	12,063,000
2	Unit Power Sales	24,703,000	3.93	971,000
3	Economy Energy	36,881,000	4.08	1,503,000
4	Other Purchases	136,640,000	3.12	4,267,000
5	TOTAL ESTIMATED PURCHASES	536,336,000	3.51	18,804,000

Schedule E-10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	AVERAGE
Customer Charge	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Energy Charge	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30
Conservation Cost Recovery	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Environmental Cost Recovery	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
Capacity Cost Recovery	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Subtotal Base	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56
Fuel Cost (Schedule E2)	24.78	25.37	32.15	26.65	26.92	28.84	29.46	29.08	30.23	33.03	27.77	23.26	28.22
Group Line Loss Multiplier	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526
Fuel Cost Recovery	24.91	25.50	32.32	26.79	27.06	28.99	29.61	29.23	30.39	33.20	27.92	23.38	28.36
Gross Receipts	2.04	2.05	2.23	2.09	2.09	2.14	2.16	2.15	2.18	2.25	2.12	2.00	2.13
Total	81.51	82.11	89.11	83.44	83.71	85.69	86.33	85.93	87.13	90.01	84.59	79.94	85.06

Note: ECCR is current 2004 factor because the projected 2005 factor has not been filed. Fuel, PPCC & ECRC are projected 2005 factors.
*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2005	JANUARY	1.978
	FEBRUARY	1.978
	MARCH	1.978
	APRIL	2.180
	MAY	2.180
	JUNE	2.180
	JULY	2.180
	AUGUST	2.180
	SEPTEMBER	2.180
	OCTOBER	2.180
	NOVEMBER	1.965
	DECEMBER	1.965
2006	JANUARY	1.965
	FEBRUARY	1.965
	MARCH	1.965
	APRIL	2.210
	MAY	2.210
	JUNE	2.210
	JULY	2.210
	AUGUST	2.210
	SEPTEMBER	2.210
	OCTOBER	2.210
	NOVEMBER	2.027
	DECEMBER	2.027

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

LINE	LINE DESCRIPTION	2002	2003	2004	2005	DIFFERENCE (%) FROM PRIOR PERIOD 2002 to 2003	2003 to 2004	2004 to 2005
	FUEL COST OF SYSTEM NET GENERATION ($)							
2	LIGHTER OIL (B.L.)	595,280	387,045	423,760	580,586	(34.98)	9.49	37.01
3	COAL	200,532,553	184,938,103	209,531,242	222,004,811	(7.78)	13.30	5.95
3a	COAL at Scherer	24,868,993	27,665,239	25,476,894	30,885,672	11.24	(7.91)	21.23
4	GAS	76,046,394	99,393,351	104,550,093	139,525,114	30.70	5.19	33.45
4a	GAS (B.L.)	393,420	279,368	241,670	424,440	(28.99)	(13.49)	75.63
6	OTHER - C.T.	1,093,946	82,237	2,676	22,145	(92.48)	(96.75)	727.54
6a	OTHER GENERATION	217,158	19,253	19,205	2,795,957	(91.13)	(0.25)	14,458.48
7	TOTAL ($)	303,747,744	312,764,596	340,245,540	396,238,725	2.97	8.79	16.46
	SYSTEM NET GENERATION (MWH)							
8	COAL	13,141,770	13,087,710	14,070,680	13,119,070	(0.41)	7.51	(6.76)
9	GAS	1,838,690	2,836,540	2,180,540	2,609,370	54.27	(23.13)	19.67
10	OTHER - C.T.	15,210	1,020	30	220	(93.29)	(97.06)	633.33
10a	OTHER GENERATION	10,200	820	790	101,010	(91.96)	(3.66)	12,686.08
11	TOTAL (MWH)	15,005,870	15,926,090	16,252,040	15,829,670	6.13	2.05	(2.60)
	UNITS OF FUEL BURNED							
12	LIGHTER OIL (BBL)	19,560	13,859	13,904	13,523	(29.15)	0.32	(2.74)
13	COAL excl. Scherer (TON)	5,044,600	5,078,332	5,405,166	5,109,413	0.67	6.44	(5.47)
14	GAS (MCF)	14,594,108	20,528,086	15,288,394	17,719,614	40.66	(25.52)	15.90
15	OTHER - C.T. (BBL)	36,207	2,467	77	534	(93.19)	(96.88)	593.51
	BTU'S BURNED (MMBTU)							
16	COAL + GAS B.L. + OIL B.L.	134,479,733	135,130,195	144,133,613	134,687,669	0.48	6.66	(6.55)
17	GAS - Generation	14,936,020	21,067,944	15,701,522	18,186,921	41.05	(25.47)	15.83
18	OTHER - C.T.	213,809	14,404	450	3,151	(93.26)	(96.88)	600.22
19	TOTAL (MMBTU)	149,629,562	156,212,544	159,835,585	152,877,741	4.40	2.32	(4.35)
	GENERATION MIX (% MWH)							
30	COAL + GAS B.L. + OIL B.L.	87.58	82.17	86.57	82.88	(6.18)	5.35	(4.26)
31	GAS - Generation	12.25	17.81	13.42	16.48	45.39	(24.65)	22.80
33	OTHER - C.T.	0.10	0.01	0.00	0.00	(90.00)	(100.00)	#N/A
33a	OTHER GENERATION	0.07	0.01	0.00	0.64	(85.71)	(100.00)	#N/A
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
36	LIGHTER OIL B.L. ($/BBL)	30.43	27.93	30.48	42.93	(8.22)	9.13	40.85
37	COAL ($/TON)	39.75	36.42	38.76	43.45	(8.38)	6.43	12.10
38	GAS +B.L. ($/MCF)	5.24	4.86	6.85	7.90	(7.25)	40.95	15.33
40	OTHER - C.T.	30.21	33.34	34.79	41.47	10.36	4.35	19.20
	FUEL COST ($) / MMBTU							
43	COAL + GAS B.L. + OIL B.L.	1.68	1.58	1.64	1.89	(5.95)	3.80	15.24
44	GAS - Generation	5.09	4.72	6.66	7.67	(7.27)	41.10	15.17
46	OTHER - C.T.	5.12	5.71	5.95	7.03	11.52	4.20	18.15
47	TOTAL ($/MMBTU)	2.03	2.00	2.13	2.57	(1.48)	6.50	20.66
	BTU BURNED / KWH							
50	COAL + GAS B.L. + OIL B.L.	10,233	10,325	10,244	10,267	0.90	(0.78)	0.22
51	GAS - Generation	8,123	7,427	7,201	6,970	(8.57)	(3.04)	(3.21)
53	OTHER - C.T.	14,057	14,121	15,000	14,323	0.46	6.22	(4.51)
54	TOTAL (BTU/KWH)	9,978	9,809	9,835	9,720	(1.69)	0.27	(1.17)
	FUEL COST (¢ / KWH)							
57	COAL + GAS B.L. + OIL B.L.	1.72	1.63	1.67	1.93	(5.23)	2.45	15.57
58	GAS - Generation	4.14	3.50	4.79	5.35	(15.46)	36.86	11.69
60	OTHER - C.T.	7.19	8.06	8.92	10.07	12.10	10.67	12.89
60a	OTHER GENERATION	2.13	2.35	2.43	2.77	10.33	3.40	13.99
61	TOTAL (¢ / KWH)	2.02	1.96	2.09	2.50	(2.97)	6.63	19.62

Schedule CCE-1

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2005 - December 2005

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) & Market Sales ($)	1,424,368	501,844	678,421	66,376	251,085	2,414,018	8,237,685	6,749,241	2,975,736	273,624	80,287	146,260	23,798,945
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	0	0	0	0	0	0	0	311,010
2a	Subtotal	1,486,570	564,046	740,623	128,578	313,287	2,414,018	8,237,685	6,749,241	2,975,736	273,624	80,287	146,260	24,109,955
3	Projected Transmission Revenue	(10,000)	(6,000)	(12,000)	(6,000)	(7,000)	(12,000)	(11,000)	(6,000)	(10,000)	(6,000)	(8,000)	(6,000)	(100,000)
4	Total Projected Capacity Payments/(Receipts) (Line 2a + 3) ($)	1,476,570	558,046	728,623	122,578	306,287	2,402,018	8,226,685	6,743,241	2,965,736	267,624	72,287	140,260	24,009,955
5	Jurisdictional %	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872
6	Projected Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,427,086	539,344	704,205	118,470	296,022	2,321,520	7,950,986	6,517,256	2,866,346	258,655	69,864	135,559	23,205,313
7	True-Up ($)													(2,851,475)
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													20,353,838
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments/(Receipts) (Line 8 x Line 9) ($)													20,368,493

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,757,001.79	96.64872%
FERC	60,923.80	3.35128%
Total	1,817,925.59	100.00000%

* Based on 2003 Actual Data

Schedule CCE-1a
REVISED 9/9/2004

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2005 - December 2005

1	Estimated over/(under)-recovery, January 2004 - December 2004 (Revised Schedule CCE-1b-1, Line 15)	$1,797,696
2	Final True-Up, January 2003 - December 2003 (Exhibit No.____(TAD-1), filed April 1, 2004	1,053,779
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2005 - December 2005)	$2,851,475
4	Jurisdictional KWH sales, January 2005 - December 2005	11,032,273,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0258)

Schedule CCE-1b
REVISED 9/9/2004

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2004 - December 2004

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,265,929	353,640	484,415	7,329	41,220	1,832,176	5,405,203	5,688,244	2,360,242	199,580	67,649	144,635	17,850,262
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(56,915)	(37,119)	(31,779)	(15,372)	(28,687)	(20,062)	(14,323)	(7,000)	(11,000)	(7,000)	(9,000)	(7,000)	(245,256)
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	1,271,216	378,724	514,838	54,159	74,735	1,874,316	5,453,082	5,743,446	2,411,444	254,782	120,851	199,837	18,351,430
5	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,226,747	365,476	496,828	52,264	72,122	1,808,750	5,262,326	5,542,533	2,327,089	245,869	116,623	192,846	17,709,471
7	Retail KWH Sales								1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.167	0.167	0.167	0.167	0.167	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	1,605,955	1,384,327	1,255,441	1,242,257	1,612,485	1,794,023	1,994,320	1,872,436	1,550,665	1,370,597	1,187,487	1,359,811	18,229,804
10	Revenue Taxes (Line 9 x .00072) ($)*	1,156	997	904	894	1,161	1,292	1,436	1,348	1,116	987	855	979	13,125
11	True-Up Provision ($)	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	1,252,572
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	1,709,180	1,487,711	1,358,918	1,345,744	1,715,705	1,897,112	2,097,265	1,975,469	1,653,930	1,473,991	1,291,013	1,463,213	19,469,251
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	482,433	1,122,235	862,090	1,293,480	1,643,583	88,362	(3,165,061)	(3,567,064)	(673,159)	1,228,122	1,174,390	1,270,367	1,759,780
14	Interest Provision ($)	2,173	2,676	3,337	4,240	5,547	7,108	6,490	2,449	(144)	58	1,338	2,644	37,916
15	Total Estimated True-Up for the Period January 2004 - December 2004 (Lines 13 + 14) ($)													1,797,696

NOTE 1: Interest is Calculated for August - December at July's rate of 0.1167 %
NOTE 2: Actual IIC Payments for January through June include Market Capacity Payments

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2005 - December 2005

	A	B	C	D	E	F	G	H	I
Rate Class	Average 12 CP Load Factor at Meter	Jan - Dec 05 Projected KWH Sales at Meter	Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Jan - Dec 05 Projected KWH Sales at Generation Col B x Col E	Projected Avg 12 CP KW at Generation Col C x Col D	Percentage of KWH Sales at Generation Col F / Total Col F	Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	61.971315%	5,115,450,000	942,299.64	1.0053010	1.00530097	5,142,566,847	947,294.77	46.61346%	53.35737%
GS	64.200053%	210,439,000	37,418.53	1.0052978	1.00529775	211,553,853	37,616.77	1.91757%	2.11880%
GSD, GSDT, GSTOU	73.167949%	2,554,407,000	398,533.75	1.0051660	1.00516604	2,567,603,169	400,592.58	23.27337%	22.56380%
LP, LPT	84.177808%	1,946,335,000	263,946.48	0.9891199	0.98911989	1,925,158,661	261,074.72	17.45010%	14.70531%
PX, PXT, RTP, SBS	101.650370%	1,073,614,000	120,568.84	0.9805725	0.98057253	1,052,756,396	118,226.49	9.54244%	6.65923%
OS - I / II	160.732077%	105,411,000	7,486.51	1.0052949	1.00529485	105,969,135	7,526.15	0.96053%	0.42392%
OS-III	100.278526%	26,617,000	3,030.03	1.0052683	1.00526827	26,757,226	3,045.99	0.24253%	0.17157%
TOTAL		11,032,273,000	1,773,283.78			11,032,365,287	1,775,377.47	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2003 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2005 - December 2005

Rate Class	A Jan - Dec 05 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 05 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RSVP	46.61346%	53.35737%	730,342	10,032,085	10,762,427	5,115,450,000	0.210
GS	1.91757%	2.11880%	30,045	398,370	428,415	210,439,000	0.204
GSD, GSDT, GSTOU	23.27337%	22.56380%	364,649	4,242,375	4,607,024	2,554,407,000	0.180
LP, LPT	17.45010%	14.70531%	273,409	2,764,846	3,038,255	1,946,335,000	0.156
PX, PXT, RTP, SBS	9.54244%	6.65923%	149,512	1,252,048	1,401,560	1,073,614,000	0.131
OS - I / II	0.96053%	0.42392%	15,050	79,704	94,754	105,411,000	0.090
OS-III	0.24253%	0.17157%	3,800	32,258	36,058	26,617,000	0.135
TOTAL	100.00000%	100.00000%	$1,566,807	$18,801,686	$20,368,493	11,032,273,000	0.185

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B