ORIGINAL

Florida Power
CORPORATION

JAMES A. McGEE
SENIOR COUNSEL

October 7, 1997

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 971004-EQ

Dear Ms. Bayó:

Enclosed for filing in the subject docket are an original and fifteen copies of Rebuttal Testimony and Exhibits of Lee G. Schuster on behalf of Florida Power Corporation.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Also enclosed is a 3.5 inch diskette containing the above-referenced document in WordPerfect format. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/kp
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cc: Parties of Record

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3201 Thirty-fourth Street South • Post Office Box 14042 • St. Petersburg, Florida 33733-4042 • (813) 866-5184 • Fax: (813) 866-4931
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for approval of early termination amendment to negotiated qualifying facility contract with Orlando Cogen Limited, Ltd. by Florida Power Corporation	Docket No.961184-EQ Submitted for filing: October 8, 1997

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the enclosed Rebuttal Testimony and Exhibits of Lee G. Schuster on behalf of Florida Power Corporation has been furnished to the following individuals by U.S. Mail this 7th day of October, 1997:

Matthew M. Childs, Esquire
Steel, Hector & Davis
215 South Monroe Street
First Florida Bank Bldg.
Suite 601
Tallahassee, FL 32301-1804

J. Roger Howe, Esquire
Office of the Public Counsel
111 West Madison Street, Room 182
Tallahassee, FL 32399-1400

Roger Yott, P.E.
Thomas Donchez
Air Products & Chemicals, Inc.
2 Windsor Plaza
2 Windsor Drive
Allentown, PA 18195

Debra Swim, Esquire
Legal Environmental Assistance Foundation, Inc.
1115 N. Gadsden Street
Tallahassee, FL 32303

Wm. Cochran Keating IV, Esquire
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Orlando Cogen Limited
8275 Exchange Road
Orlando, FL 32809

Attorney

ORIGINAL

Florida Power
CORPORATION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 961184-EQ

In Re: Petition for Approval of Early Termination Amendment of Negotiated Qualifying Facility Contract with Orlando Cogen Limited, Ltd. by Florida Power Corporation

REBUTTAL TESTIMONY AND EXHIBITS OF LEE G. SCHUSTER

FLORIDA POWER CORPORATION

DOCKET NO. 961184-EQ

REBUTTAL TESTIMONY OF LEE G. SCHUSTER

Q. Please state your name and business address.

A. My name is Lee G. Schuster. My business address is Post Office Box 14042, St. Petersburg, Florida, 33733.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony on behalf of Florida Power Corporation ("Florida Power") was filed on August 27, 1997.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of Mr. Paul Stallcup on behalf of the Commission Staff and Mr. Hugh Larkin on behalf of the Office of Public Counsel. With respect to Mr. Stallcup's testimony, I will address four subject areas: (1) risk and cost/benefit analysis, (2) natural gas price forecast assumptions, (3) power plant construction forecast assumptions, and (4) the risk adjusted discount rate methodology.

With respect to Mr. Larkin, I will discuss and respond to each of the five subject areas addressed by his testimony: (1) risk and cost/benefit analysis, (2) the appropriate discount rate, (3) intergenerational fairness, (4) the issue of stranded costs, and (5) his "alternative proposal."

I. REBUTTAL TO STAFF'S DIRECT TESTIMONY

Q. Please summarize your overall conclusions regarding Mr. Stallcup's testimony.

A. With the exception of several secondary issues, I am in general agreement with Mr. Stallcup's risk analysis, in particular, the use of a reputable third party forecast to test the reasonableness of forecast assumptions and the use alternative forecasts to conduct a risk sensitivity analysis. However, in implementing this methodology, a material arithmetic error was made. When this error is corrected, Mr. Stallcup's risk analysis offers strong support for approval of the OCL contract buyout. His corrected base case yields a net present value (NPV) savings of $100.6 million (compared to $34.6 million from the analysis in my direct testimony), with sensitivity results of $89.3 million for his pessimistic case and $108.5 million for his optimistic case. In other words, the corrected results of Mr. Stallcup's own analysis demonstrate that the proposed OCL contract buyout offers very substantial savings to customers with virtually no risk that changes in assumed conditions could eliminate those savings.

Moreover, when the secondary issues of disagreement that I discuss below are properly treated in the analysis, the expected savings from the buyout become even greater.

1. Risk and Cost/Benefit Analysis

Q. What is your primary concern with respect to Mr. Stallcup's testimony and his risk and cost/benefit analysis of the proposed OCL contract buyout?

A. Mr. Stallcup's analysis contains a material arithmetic error in the treatment of his risk adjusted discount rate which invalidates the results of his study cases. In Mr. Stallcup's discussion of the derivation of a risk adjusted discount rate at pages 8-9 of his testimony, he correctly indicates that it consists of the sum of a risk free discount rate and a risk premium. However, in calculating the actual risk adjusted discount rates used in his analysis of the OCL buyout (Stallcup Exhibit PWS-4), the risk premium is mistakenly subtracted from the risk free rate. My rebuttal Exhibit LGS-8 shows both Mr. Stallcup's calculation and a corrected calculation in which the risk adjusted discount rate is computed as the sum of the risk free rate and a risk premium.

Q. If the correct risk adjusted discount rate had been used in Mr. Stallcup's analysis, what would the results have been?

A. The results of a corrected analysis are summarized in my rebuttal Exhibit LGS-9. These cases are based entirely on Mr. Stallcup's

assumptions and methodology as described in his testimony, including the use of a natural gas price forecast prepared by Data Resources, Inc. (DRI). The only difference between the results presented in Mr. Stallcup's Exhibit PWS-5 and my Exhibit LGS-9 is the correction of the error described above and as shown in Exhibit LGS-8. Mr. Stallcup's methodology yields a NPV savings of $100.6 million for the DRI base case (detailed in rebuttal Exhibit LGS-10), NPV savings of $89.3 million for the DRI pessimistic case (detailed in rebuttal Exhibit LGS-11), and NPV savings of $108.5 million for the DRI optimistic case (detailed in rebuttal Exhibit LGS-12). After weighting the sensitivity cases, they produce an expected NPV of savings of $99.2 million, which suggests that there is a negligible probability that the NPV savings could be negative.

Q. What is your response to Mr. Stallcup's alternative risk analysis based on a hybrid 10.9% discount rate as described on page 16 of his testimony?

A. This risk analysis is based on the average of Florida Power's discount rate of 8.81% and the 13% discount rate suggested by Mr. Larkin. Mr. Stallcup offers no justification for using a 10.9% discount rate whatsoever, nor does he endorse its use. Clearly, any number of "mixed bag" discount rates could be created in a similar manner, without ever addressing the underlying question of whether the rate is appropriate. For example, Mr. Larkin's range of 13-19% could be averaged to arrive at 16.5%, or one could average the 15.5% midpoint

of Mr. Larkin's range with Florida Power's 8.81% discount rate to arrive at 12.15%, etc. Rather than respond to a calculation by Mr. Stallcup using Mr. Larkin's data, I will address Mr. Larkin's testimony regarding discount rates directly in the next section of my testimony.

Q. Have you performed a cost/benefit analysis using Mr. Stallcup's risk adjusted discount rate in combination with Florida Power's forecast assumptions?

A. Yes. Mr. Stallcup states that he believes that his analysis is more comprehensive than that presented in the testimony of Florida Power or Public Counsel witness Larkin. While I believe that it is fair to test the benefits of the proposed OCL contract buyout using an alternative fuel price forecast such as DRI's, I do not believe that it is appropriate to dispense entirely with Florida Power's fuel forecast as Mr. Stallcup has done. Mr. Stallcup argues that it is appropriate to use the DRI forecast instead of Florida Power's forecast. As discussed below, I take issue with this position and have concerns regarding the data he uses to support his arguments. I also take issue below with the particular DRI index selected by Mr. Stallcup to escalate the cost of the combined cycle unit used in the analysis to replace the last 10 years of the OCL contract. As a result, I have prepared a cost/benefit analysis which restates Mr. Stallcup's results using Florida Power's forecast assumptions.

Q. What is the result of Mr. Stallcup's adjusted risk premium analysis using Florida Power's forecast assumptions in place of the DRI forecast data?

A. The result of this cost benefit analysis is summarized in my rebuttal Exhibit LGS-13. This case is based on Mr. Stallcup's risk premium methodology as described in his testimony. In addition to correcting the discount rate error described above, only two changes have been made to the assumptions used in Mr. Stallcup's base case presented in his Exhibit PWS-5: (1) the use of Florida Power's fuel forecast in place of the DRI fuel forecast, and (2) the use of DRI's *Fixed Investment, Durable Equipment* price index rather than the DRI *Public Utility Structures* price index. Both of these changes are discussed below. The results of this analysis indicate a NPV customer benefit of $119.4 million.

2. Natural Gas Price Forecast Assumptions

Q. On page 4 of his testimony, Mr. Stallcup states that Florida Power's natural gas price forecast may substantially understate the future market price of natural gas. Do you agree with this conclusion?

A. No, I do not, and in certain respects, neither does the data offered by Mr. Stallcup in support his conclusion. He bases his conclusion on two comparisons. First, he compares the Florida Power price forecast to the gas price forecasts submitted by other Florida utilities in their 1997

Ten Year Site Plans. Second, he compares the Florida Power forecast to the DRI base case natural gas price forecast.

Q. How does Florida Power's natural gas price forecast to the forecasts submitted by other Florida utilities in their 1997 Ten Year Site Plans?

A. The Ten Year Site Plan gas price forecasts that Mr. Stallcup refers to and shows in his Exhibit PWS-1 only cover the period 1997-2006. In 2006, the final year of these forecasts, the majority of the forecasts, including Florida Power's, indicate a natural gas price between $3.00/MMBtu and $4.00/MMBtu. In forecasting natural gas prices ten years in the future, this $1 range is not unreasonable, especially when one recognizes that this same group of forecasts start out with a price range of about $2 (from slightly over $2.00/MMBtu to approximately $4.00/MMBtu) in 1997, the first year of the forecast.

Q. What is the source for the gas price forecasts attributed by Mr. Stallcup to the utilities' 1997 Ten Year Site Plans for the interval 2007-2023?

A. Mr. Stallcup has presented forecast data through 2023 in his Exhibit PWS-1 and cited as his source the 1997 Ten Year Site Plans for each of the respective utilities, even though the plans contain data only through 2006. My direct testimony addressed the issue of Staff creating long term forecasts based on shorter term forecasts prepared by a utility and attributing the entire forecast to the utility. If this practice has been continued in Mr. Stallcup's testimony, there can be no insight gained from comparing these utility gas price forecasts

beyond the year 2006, since that portion of the forecast was not prepared, reviewed or issued by the respective utilities.

Q. What bearing do historical price patterns for natural gas have on Mr. Stalloup's conclusions and the validity of the Florida Power natural gas price forecast?

A. Historical natural gas prices for the period 1973-97 are summarized in my rebuttal Exhibits LGS-14 and LGS-15, which are based on data from the Energy Information Administration's *Monthly Energy Review* for August 1997. The movements in natural gas prices over the last 25 years may be divided into two periods that are relevant to forecasting prices today. First, from the early 1970's until 1985 there was a ten-fold increase in the price of natural gas, from approximately $0.30/MMBtu to well over $3.00/MMBtu. During this period users experienced repeated price shocks and forecasters regularly revised their price forecasts upward. During 1985-87 the price fell to approximately $2.25/MMBtu and has remained essentially at this level since that time. During recent years, the persistence of stable, relatively low natural gas prices has been an actively debated and much publicized topic. Most recently, during 1996-97 there has been increased volatility in prices, with brief price spikes as high as $4.00/MMBtu, while returning to the neighborhood of $2.25/MMBtu.

Given this historical context, it is not at all surprising that different forecasters have different views regarding the future of natural gas prices. I will agree with Mr. Stalloup that DRI and Florida Power have

different natural gas price forecasts, but it is no more valid to reject Florida Power's forecast because it "may substantially understate the future market price of natural gas" than to reject DRI's forecast because it may substantially overstate the price. As history has shown, only actual prices in the future will reveal which forecast is more accurate. For example, if a forecaster in 1986 had predicted that natural gas prices would fall to approximately $2.25/MMBtu and remain near that level for a decade, there is little doubt that such a forecast would receive the same type of skepticism that Mr. Stallcup has directed at Florida Power's price forecast. Yet, that forecast would have proven to be absolutely correct and other forecasts of much higher natural gas prices based on historical trends would have proven to be highly misleading.

3. Power Plant Construction Forecast Assumptions

Q. Mr. Stallcup maintains that DRI's *Fixed Investment, Durable Equipment* price index used by Florida Power to project combined cycle power plant construction costs during the buyout period is not correct, and that the DRI *Public Utilities Structures* price index should be used instead. What is your response to his contention?

A. Simply put, a combined cycle power plant is much more like a large machine than it is like a structure or building. I have provided data for the cost breakdown of a typical combined cycle power plant in rebuttal Exhibit LGS-16 which demonstrates that approximately 90% of the

cost is related to equipment and only 10% is related to structures. In reality, the components of a combined cycle power plant relate to both the cost indices for equipment and for structures. A more refined escalation method would weight these two indices in proportion to the contribution of each index to the cost of the various components of a combined cycle power plant. However, in the case of a combined cycle unit, where the cost is determined predominately by one index, it would be a reasonable approximation to use the dominate index to project construction costs.

Q. How do the definitions of the DRI cost indices for equipment and for structures relate to the components of a combined cycle power plant?

A. One of the three largest components in the equipment cost index is electrical machinery expenditures, which includes many of the main components of combined cycle power plants, such as fabricated metals, engines, turbines and electrical equipment. In a combined cycle power plant, the turbines are the single largest cost component, and most of the balance of the equipment and materials used to construct the plant are included in the equipment index. By contrast, the index for public utility structures includes such items as railroad tracks, stations, telephone, electric and gas transmission and distribution systems, and oil and gas well drilling and exploration expenditures. As a result, the public utility structures index includes many items that bear no relation to power plant construction.

Q. How can the relative importance of these two cost indices to the escalation of power plant construction costs be determined?

A. The proper way to determine an appropriate weighting is to use a cost breakdown for a power plant and identify those costs which relate to each index. This data has been provided in my rebuttal Exhibit LGS-16, which summarizes the construction cost for a typical 250 megawatt combined cycle power plant. This cost breakdown demonstrates that only approximately 10% of the total cost is related to the structures index. The largest cost component is mechanical equipment which includes the turbines, the primary component of a power plant of this type. The remaining cost categories include the balance of equipment and materials required to construct this type of power plant.

Q. What can be concluded from this analysis regarding the proper cost index to use to forecast the construction cost for combined cycle power plants?

A. The construction costs for a combined cycle power plant are predominately related to the equipment index. Due to the relatively minor contribution of the structures index it seems reasonable to estimate future construction costs using only the equipment index as I have done in my NPV analysis. I believe that Mr. Stallcup is incorrect to select the structures index in preference to the equipment index.

Q. What is the effect of using the Public Utility Structures index in Mr. Stallcup's analysis instead of the Fixed Investment, Durable Equipment price index used by Florida Power?

A. As Mr. Stallcup points out on page 7 of his testimony, the effect of using the Public Utility Structures index in place of the Fixed Investment, Durable Equipment index is to reduce the NPV of the proposed OCL contract buyout by approximately $4.7 million (from $32.7 million to $28.0 million in Mr. Stallcup's example). As discussed above, I believe this is an unjustified and inappropriate reduction.

4. The Risk Adjusted Discount Rate Methodology

Q. Do you have any other concerns regarding Mr. Stallcup's risk adjusted discount rate methodology?

A. Yes, I do. Mr. Stallcup claims to be measuring volatility or risk by means of computing standard deviations, as described on page 12 of his testimony. However, the variances upon which he calculates the standard deviations are simply the differences between his DRI base case and his DRI expected value case. As a result, all Mr. Stallcup is actually measuring is the symmetry, or lack thereof, of the DRI optimistic and pessimistic cases with respect to the DRI base case. By symmetry I mean the degree to which the optimistic and pessimistic cases deviate from the base case. If they deviate equally, for example the optimistic case being 20% higher than the base and the pessimistic being 20% lower than the base, the cases are symmetric. However,

if the optimistic case were 25% higher than the base and the pessimistic 15% lower than the base the cases would be asymmetric. The key point is that if the cases are symmetric, the expected value will be equal to the base case and the variance computed by Mr. Stallcup will be zero. Conversely, the expected value will deviate from the base case and result in a non-zero variance if the cases are not symmetric.

Q. What is really meant by the risk of the forecast and how can it be measured?

A. In essence, risk may be defined as the probability that the actual value for the variable being forecasted is different from the predicted base case value. The degree to which the optimistic and pessimistic forecasts diverge from the base case offers a way to measure this risk. For example, if the three forecasts diverge only slightly and remain very close together, it can be concluded that there is a high probability that the variable being forecasted will have an actual value close to the base case and therefore less risk. Conversely, if the three forecasts diverge widely, there is much more uncertainty regarding the actual value of the variable being forecasted and therefore more risk.

Q. Can you provide an example as to why Mr. Stallcup's methodology fails to measure this forecast risk in an acceptable manner?

A. Yes. This can be illustrated by comparing the risk of the following two forecasts. The first forecast is symmetric, with the optimistic case being 40% higher than the base case and the pessimistic case being

40% lower than the base case. The second forecast is not symmetric, with the optimistic case being 3% higher than the base and the pessimistic case being 1% lower than the base case. Common sense suggests that the first forecast has far more risk than the second forecast. However, Mr. Stalcup's methodology would reach the opposite conclusion by determining that the first forecast has zero risk because it is symmetric and the second forecast has a level of risk that is a function of the degree to which it is not symmetric.

Q. What is your overall opinion of Mr. Stalcup's risk adjusted discount rate methodology?

A. The risk adjusted discount rate methodology works reasonably well when the risk premium is determined on an *a priori* basis. This is the case for the capacity payments in the contract and replacement cases as well as for the contract buyout cost. However, the risk premiums computed for the projected energy costs in the contract and replacement case are suspect for the reasons discussed above. There seems to be little, if any, justification for equating the degree of asymmetry among the base, high and low forecast cases with risk.

II. REBUTTAL TO PUBLIC COUNSEL'S DIRECT TESTIMONY

Q. Please summarize your overall conclusions with regard to Mr. Larkin's testimony.

A. Mr. Larkin's discussion deals only with those selected elements of the OCL buyout transaction that support his arguments. As I discuss below, each of Mr. Larkin's arguments are either based on erroneous assumptions, or his arguments are incomplete or misleading. In summary, Mr. Larkin's conclusions and his purported alternative proposal for the OCL contract buyout should be rejected.

1. Cost/Benefit Analysis

Q. On page 2 of his testimony, Mr. Larkin states that the only amount in Florida Power's net present value calculation that can be determined to be fixed, known and measurable is the amount that ratepayers will be charged for the buyout. Do you agree with his statement?

A. No. The majority of the savings from the OCL contract buyout will result from avoiding the known capacity payments required by the existing contract during the period 2014-2023. If the existing contract remains in place, customers will be required to pay $458,990,000 in capacity payments during this period with virtually the same certainty that Mr. Larkin ascribes to the cost of the OCL contract buyout. Mr. Stallcup, at page 8 of his testimony, agrees that the capacity costs under the contract are known with certainty and treats them as such in his risk analysis. Thus, Mr. Larkin begins his risk analysis with a fundamentally flawed premise.

Q. What is your response to Mr. Larkin's claim at page 3 of his testimony that the risk that the ratepayer takes is extremely high because the savings from the transaction are based in part on future projections.

A. Mr. Larkin attacks the projections and underlying assumptions used in Florida Power's projection of customer savings exclusively on the basis that they are, of necessity, projections and assumptions that cannot be determined to be fixed, known and measurable. Based solely on this observation, he concludes that Florida Power's NPV calculation is "extremely speculative" and that "the risk ratepayer takes is extremely high". In doing so, he ignores the fact that this is necessarily the nature of most, if not all, proposals which offer future savings to customers. Often, none of the components of projected savings and costs are fixed, but must be estimated based on reasonable assumptions. Mr. Larkin's testimony classifies projected costs and benefits into two risk categories. Projected costs and benefits which are fixed, known and measurable have zero risk; all other projections are, according to Mr. Larkin, subject to extreme risk. Mr. Larkin's conclusions based on this simplistic risk analysis lack any credible analytical basis whatsoever and should be dismissed.

2. <u>Discount Rate</u>

Q. What is wrong with Mr. Larkin's statement that the use of an 8.67% discount rate to calculate the net present value benefit to ratepayers is inappropriate and not reasonable?

A. Mr. Larkin completely misses the point when he states that the use of Florida Power's cost of capital as a discount rate is inappropriate simply because it is Florida Power's cost of capital. As is normally the case in this kind of present value analysis, the utility's cost of capital is used as a proxy for the customers' discount rate. This discount rate concept has been used by Florida Power in numerous dockets and filings over many years and has been accepted by the Commission, Staff and other parties to these dockets. As discussed below, the theoretical arguments regarding the appropriate value for a customer discount rate span the range from 2-3% up to 18%. Given this wide range, a proxy value of 8-9% is not at all unreasonable.

Q. What is wrong with Mr. Larkin's statement on page 6 that it would be unlikely that any sophisticated investor would accept an 8.67% rate of return on his investment?

A. Mr. Larkin appears to have erroneously assumed that because Florida Power used an 8.67% discount rate to compute the NPV of customer savings, that the OCL contract buyout provides an effective return of 8.67%. This is an incorrect conclusion; and consequently Mr. Larkin's arguments regarding the acceptability of an 8.67% return on investment are irrelevant. Florida Power calculated a NPV benefit of $32.5 million using an 8.67% discount rate and subsequently a NPV benefit of $34.6 million using an 8.81% discount rate (based on updated assumptions included in late-filed Exhibit No. 8 to my deposition by Staff). This calculation clearly demonstrates that the

effective return to customers is higher than 8.81% because the resulting NPV is positive.

The effective rate of return for the proposal is determined by solving for the discount rate which makes the NPV equal to zero. This computation (requested by Staff as late-filed Exhibit No. 1 to my deposition) results in a discount rate of 12.19%. The 12.19% rate is the effective (after-tax) return of the cash flow stream when this proposal is viewed as an investment. In other words, if the buyout payments of $9.8 million per year during the period 1997-2001 were deposited in an investment account at a 12.19% rate of return, the balance of this investment would grow such that, beginning in 2014 amounts equal to the projected annual customer savings could begin to be withdrawn from this investment account. Withdrawals could be made each year in amounts equal to projected annual customer savings, and when the final amount is withdrawn in 2023 the investment balance would be reduced to zero.

Q. Is Mr. Larkin's proposed discount rate of 13-18% appropriate for this type of analysis?

A. No. A discount rate based on the interest rate for an unsecured loan or credit card is only one of several concepts included in the theory of customer discount rates. Mr. Larkin makes no mention of the equally valid argument that customers may have no credit card debts whatsoever, but instead make regular deposits to a passbook savings account earning 3-4% (before taxes). Alternatively, other customers

may make investments in bonds at an 8% yield. To illustrate the complications of the customer discount rate argument, there are also customers who have a credit card debt balance and are nevertheless also putting money aside in a savings account. Mr. Larkin conveniently ignores these other arguments which would suggest lower customer discount rates and reveal the complexity of the issue he raises. It is for precisely these reasons that a reasonable, well understood proxy for the customer discount rate has been established by convention and consistently used to compute the net present value of customer savings in analyses such as the OCL contract buyout analysis.

Q. What else has Mr. Larkin overlooked in his discount rate discussion?

A. In his discussion of acceptable investment returns, Mr. Larkin makes no distinction between a pre-tax return on investment and an after-tax return on investment. For a typical customer, the 12.19% return represented by the OCL contract buyout corresponds to an after-tax rate of return. In order for an investment opportunity to provide a comparable return it would need to offer a higher pre-tax return. For example, a marginal federal income tax rate of 15% to 28% would imply that the investment must provide a pre-tax return of 14.34% to 16.93% in order to be comparable to the OCL buyout. As a result, I would challenge Mr. Larkin's assertion that no sophisticated investor would be likely to accept the return inherent in the proposed OCL contract buyout when viewed as an investment.

Q. Do you agree with Mr. Larkin that the appropriate discount rate must reflect the nature of a high risk investment?

A. No. Mr. Larkin's characterization that substantial risk is related to Florida Power's proposal is unsupported speculation. He has provided no basis for this conclusion which justifies his arguments for a higher discount rate.

3. Intergenerational Fairness

Q. Do you agree with Mr. Larkin's assertion that there are intergenerational inequities associated with the OCL contract buyout?

A. No, I do not. As I pointed out in my direct testimony, the buyout does not create intergenerational inequity, but rather helps to counterbalance an existing intergenerational inequity inherent in the structure of the original OCL contract. Compared to the costs of the unit avoided by the OCL contract, current customers are still better off under the contract even with the buyout cost through 2002. To the extent that intergenerational fairness is an issue in this proceeding, it weighs strongly in favor of -- not against -- approval of the OCL buyout.

Q. Do you agree with Mr. Larkin's argument on page 8 that the low capacity payments made by customers during the early years of the OCL contract is not an intergenerational inequity, but simply compensation for a higher risk of non-performance by OCL?

A. Absolutely not. Mr. Larkin is correct only to the extent that one of the reasons for adopting the value of deferral methodology, which "back-end loaded" the capacity payment stream, was to ensure QF performance for the duration of the contract. The point, however, is that to achieve this important performance-ensuring objective, of necessity, an intergenerational inequity was created compared to traditional revenue requirements ratemaking. To suggest, as Mr. Larkin does, that this shifting of substantial costs from current to future customers was done to compensate current customers for a higher risk of non-performance is absurd. By heavily back-end loading the QF's capacity payments, the likelihood that the QF will perform throughout the term of the contract is greatly enhanced. Thus, the risk of non-performance is reduced in each and every year of the contract, even though the cost of this risk reduction is borne by future customers to the benefit of current customers.

Moreover, viewed in terms of circumstances as we know them today, non-performance by OCL can no longer be considered a "risk." Indeed, the entire premise of the OCL contract buyout is that, due to changed economic circumstances, there is value in paying OCL not to perform during the last ten years of the contract. Given this demonstrated value of non-performance under the contract, it makes no sense to perpetuate the notion that current customers should be compensated, or future customers should pay, for a risk that has now become a benefit.

4. Stranded Costs

Q. Is there any merit in Mr. Larkin's discussion of the effect of this transaction on the issue of stranded cost?

A. No. My direct testimony made it clear that the issue of potential strandable costs need not be addressed as part of the Commission's decision regarding the OCL contract buyout. Mr. Larkin makes the error of assuming that, to the extent that the OCL buyout reduces potential strandable costs, it somehow precludes a process of netting stranded costs and benefits in the future. Nothing could be further from the truth. In the context of stranded costs, the OCL buyout constitutes a mitigation of potential future strandable costs. Such mitigation efforts will serve only to reduce the level of stranded costs which may exist in the future and in no way conflicts with the offsetting of stranded costs and benefits discussed by Mr. Larkin. Mr. Larkin seems to believe that a cost reduction effort on the part of Florida Power is somehow one-sided and inequitable unless it is accompanied by some final accounting of stranded costs and benefits. Mr. Larkin has digressed into a speculative discussion related to the future restructuring of the electric industry which has no bearing on the proposed OCL contract buyout.

5. Larkin's "Alternative Proposal"

Q. What is wrong with Mr. Larkin's proposal that Florida Power make the buyout payments and receive the benefits of the buyout transaction rather than Florida Power's customers?

A. In essence, Mr. Larkin is proposing that Florida Power convert an opportunity to provide at least $472 million in savings to its customers into an transaction which would benefit only Florida Power's shareholders. If Florida Power had made this proposal itself it would undoubtedly have been sharply criticized, and properly so. The fact that Mr. Larkin has advanced such a dubious proposal does not change its essential nature.

Q. Is Mr. Larkin correct in assuming that Florida Power could undertake the OCL buyout transaction in place of the customers, with the transaction remaining unchanged?

A. No. Mr. Larkin makes the simplistic and erroneous assumption that the transaction would be unchanged if the Company were to "step into the shoes of the customer" and engage in the buyout transaction rather than Florida Power's customers. This is simply not the case. The Company's proposal will deliver savings directly to customers in the form of lower electric rates. If Florida Power were to receive these same benefits in the form of revenues from customers, this revenue would represent taxable income to the Company. In order for Florida Power to earn its authorized rate of return as proposed by Mr. Larkin,

it would be necessary to collect revenues corresponding to Florida Power's pre-tax rate of return. Mr. Larkin gives no indication that he recognizes the implications of his own proposal, and he has not presented any form of analysis to substantiate his claims.

Q. Under his alternate proposal, Mr. Larkin claims that the Company will receive a rate of return equal to its current authorized rate of return and at the same time be able to reduce its future capacity and energy costs and achieve its stated goal of offering competitive prices to its customers. How is this possible?

A. It is not. In touting his proposal, Mr. Larkin double counts the resulting benefits. Obviously, if the Company receives the future benefits of the buyout in the form of higher revenues from customers in compensation for making the near-term buyout payments, there would, in all probability, be no rate reduction for customers.

Q. What is your reaction to Mr. Larkin's statement that Florida Power will suffer no harm if the Commission were to deny its petition?

A. Mr. Larkin's statement is irrelevant to the subject at hand. It is Florida Power's customers, not the Florida Power, who will be directly harmed if the Company's petition is rejected and customer's are denied the benefits which would result from the OCL contract buyout. Mr. Larkin is simply rehashing the argument previously made by Public Counsel in its motion to dismiss Florida Power's request for a hearing on its petition, claiming Florida Power lacked standing to advocate actions it

believed to be in the best interests of its customers. The Commission rejected that argument before and it has gotten no better with age.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Corrected Calculation of Risk Adjusted Discount Rates

	(1)	(2)	(3)	(4)	(5)
	Contract Case		Replacement Case		
Calculation per Stallcup testimony:	Capacity	Energy	Capacity	Energy	Cost
Risk Free Discount Rate	6.77%	6.77%	6.77%	6.77%	6.77%
Relative Risk Premium (subtracted)	0.69%	3.69%	3.29%	4.53%	0.00%
Risk Adjusted Discount Rate	6.77%	3.74%	3.62%	2.24%	6.77%
Tax rate per Exhibit PWS-4 25.25%					
After-tax RADR	5.69%	2.80%	2.69%	1.68%	5.09%
Corrected calculation:					
Risk Free Discount Rate	6.77%	6.77%	6.77%	6.77%	6.77%
Relative Risk Premium (added)	0.69%	3.69%	3.29%	4.53%	0.00%
Risk Adjusted Discount Rate	6.77%	9.89%	10.06%	11.30%	6.77%
Tax rate per Exhibit PWS-4 25.25%					
After-tax RADR	5.09%	7.32%	7.49%	8.44%	5.09%

Docket No. 961184-EQ
Exhibit No. _____ LGB-6

Corrected
Summary of Risk Analyses
On Proposed OCL Contract Buyout

Risk Adjusted Discount Rate Method

	(1)	(2)	(3)
Unadjusted DRI Scenario Probabilities	NPV	Probability	Weighted NPV
DRI Pessimistic Case	88,331	20%	22,333
DRI Base Case	100,888	80%	80,270
DRI Optimistic Case	108,485	20%	28,821
Expected NPV			[illegible]
Adjusted DRI Scenario Probabilities			
DRI Pessimistic Case	88,331	10%	8,833
DRI Base Case	100,888	60%	60,336
DRI Optimistic Case	108,485	30%	31,946
Expected NPV			[illegible]

Docket No. 961184-EQ
Exhibit No. _____ LGS-10

Florida Power Corporation
Savings to FPC Customers Due to OCL Contract Buyout
Corrected DRI Base Case
[illegible]

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Contract Case			Replacement Case				
Year	Capacity	Energy	(1)+(2) Total	Capacity	Energy	Buyout Cost	(4)+(5)+(6) Total	(3)-(7) Customer Savings
1997	0	0	0	0	0	9,881	9,881	(9,881)
1998	0	0	0	0	0	9,881	9,881	(9,881)
1999	0	0	0	0	0	9,881	9,881	(9,881)
2000	0	0	0	0	0	9,881	9,881	(9,881)
2001	0	0	0	0	0	9,881	9,881	(9,881)
2002	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	38,322	22,542	[illegible]	7,989	22,864	0	30,853	28,012
2015	38,177	23,264	61,440	8,157	23,749	0	31,936	29,504
2016	40,116	24,127	[illegible]	8,411	24,677	0	33,088	31,155
2017	42,171	24,815	[illegible]	8,644	25,606	0	34,250	32,736
2018	44,312	25,647	[illegible]	8,878	26,579	0	35,457	34,501
2019	46,579	26,497	73,076	9,124	27,639	0	36,763	36,313
2020	48,963	27,440	[illegible]	9,336	28,742	0	38,077	38,316
2021	51,483	26,314	[illegible]	9,594	29,889	0	39,483	40,284
2022	54,070	29,293	[illegible]	9,891	31,090	0	40,980	42,373
2023	56,836	30,273	87,109	10,195	32,314	0	42,499	44,610
Total 2014-30	[illegible]	[illegible]	721,191	[illegible]	272,139	0	353,357	367,894
RADR Rate	6.00%	7.33%		7.49%	8.44%	6.00%		
NPV	163,370	[illegible]	[illegible]	[illegible]	[illegible]	43,770	188,393	189,668

Docket No. 961184-EQ
Exhibit No. ________ LGS-11

Florida Power Corporation
Savings to FPC Customers Due to OCL Contract Buyout
Corrected DRI Pessimistic Case
($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Contract Case			Replacement Case				
			(1)+(2)				(4)+(5)+(6)	(3)-(7)
						Buyout		Customer
Year	Capacity	Energy	Total	Capacity	Energy	Cost	Total	Savings
1997	0	0	0	0	0	9,881	9,881	(9,881)
1998	0	0	0	0	0	9,881	9,881	(9,881)
1999	0	0	0	0	0	9,881	9,881	(9,881)
2000	0	0	0	0	0	9,881	9,881	(9,881)
2001	0	0	0	0	0	9,881	9,881	(9,881)
2002	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	36,322	27,615	63,937	10,488	30,220	0	40,708	23,230
2015	38,177	28,870	67,047	10,937	31,950	0	42,887	24,160
2016	40,116	30,365	70,480	11,455	33,829	0	45,284	25,197
2017	42,171	31,700	73,871	11,890	35,927	0	47,817	26,055
2018	44,312	33,135	77,447	12,583	37,925	0	50,508	26,939
2019	46,579	34,710	81,289	13,152	40,212	0	53,363	27,926
2020	48,953	36,463	85,416	13,718	42,598	0	56,316	29,100
2021	51,463	38,067	89,530	14,372	45,199	0	59,571	29,960
2022	54,070	39,911	93,982	15,090	47,929	0	63,019	30,962
2023	56,836	41,808	98,644	15,796	50,830	0	66,626	32,018
Total 2014-23	458,999	342,694	801,673	129,449	396,669	0	526,168	275,565
RADR Rate	6.66%	7.35%		7.40%	8.44%	6.60%		
NPV	153,376	71,957	225,333	28,317	65,908	43,778	136,002	89,331

Docket No. 961184-EQ
Exhibit No. _____ LGS-12

Florida Power Corporation
Savings to FPC Customers Due to OCL Contract Buyout
Corrected Bill Optimistic Case
(000s)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Continue Case			Replacement Case				
Year	Capacity	Energy	(1)+(2) Total	Capacity	Energy	Buyout Cost	(4)+(5)+(6) Total	(3)-(7) Customer Savings
1997	0	0	0	0	0	9,881	9,881	(9,881)
1998	0	0	0	0	0	9,881	9,881	(9,881)
1999	0	0	0	0	0	9,881	9,881	(9,881)
2000	0	0	0	0	0	9,881	9,881	(9,881)
2001	0	0	0	0	0	9,881	9,881	(9,881)
2002	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2014	36,322	19,523	55,845	6,488	18,716	0	25,207	30,639
2015	38,177	20,003	58,179	6,551	19,173	0	25,734	32,445
2016	40,116	20,615	60,731	6,696	19,631	0	26,286	34,445
2017	42,171	21,071	63,243	6,755	20,132	0	26,886	36,357
2018	44,312	21,601	65,913	6,848	20,592	0	27,440	38,472
2019	46,579	22,209	68,788	6,695	21,139	0	28,094	40,694
2020	48,953	22,836	71,788	7,020	21,643	0	28,663	43,126
2021	51,463	23,351	74,815	7,116	22,149	0	29,265	45,550
2022	54,070	24,029	78,099	7,251	22,698	0	29,949	48,150
2023	56,836	24,657	81,493	7,366	23,248	0	30,613	50,880
Total 2014-23	463,999	219,095	678,095	69,916	209,116	0	279,135	469,799
RADR Rate	6.69%	7.32%		7.49%	8.44%	6.69%		
NPV	163,376	45,719	209,095	14,259	35,645	43,779	93,699	165,496

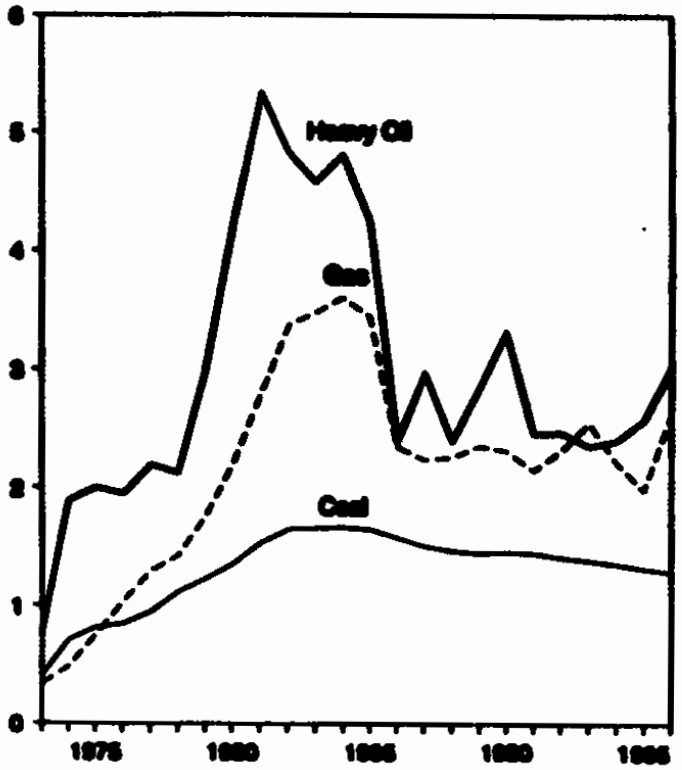
Docket No. 961184-EQ
Exhibit No. ________ LGS-13

Florida Power Corporation
Savings to FPC Customers Due to OCL Contract Buyout
Using Risk Adjusted Discount Rates and FPC Assumptions
($000)

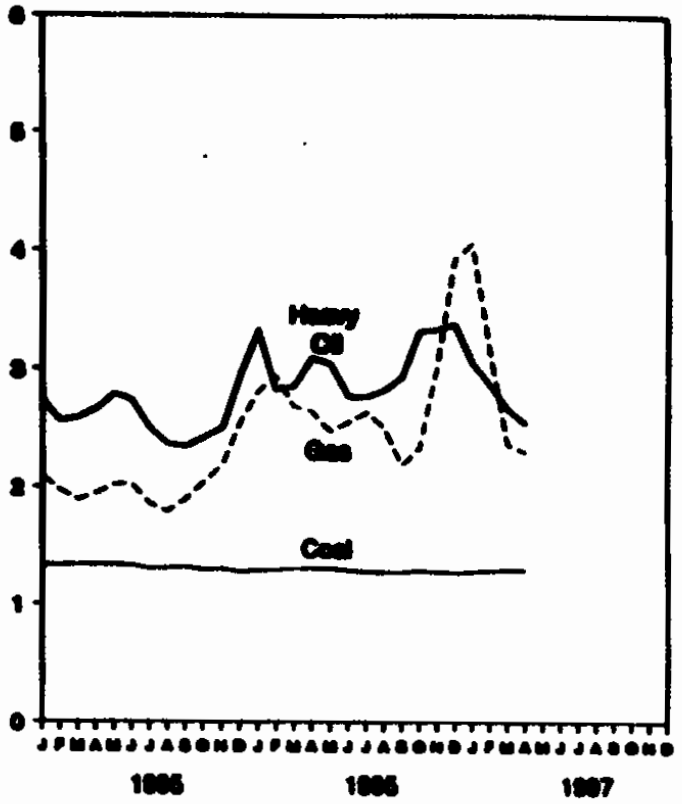
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Contract Case			Replacement Case				
			(1)+(2)				(4)+(5)+(6)	(3)-(7)
Year	Capacity	Energy	Total	Capacity	Energy	Buyout Cost	Total	Customer Savings
1997	0	0	0	0	0	9,881	9,881	(9,881)
1998	0	0	0	0	0	9,881	9,881	(9,881)
1999	0	0	0	0	0	9,881	9,881	(9,881)
2000	0	0	0	0	0	9,881	9,881	(9,881)
2001	0	0	0	0	0	9,881	9,881	(9,881)
2002	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0
2014	36,322	21,[illegible]	[illegible]	[illegible]	16,026	0	21,779	36,229
2015	38,177	22,230	60,415	[illegible]	16,264	0	22,080	38,336
2016	40,116	22,872	[illegible]	[illegible]	[illegible]	0	22,410	40,578
2017	42,171	23,401	[illegible]	[illegible]	16,751	0	22,748	42,824
2018	44,312	24,012	[illegible]	[illegible]	[illegible]	0	23,083	45,231
2019	46,579	24,645	71,224	[illegible]	17,282	0	23,464	47,770
2020	48,953	25,300	74,321	[illegible]	17,[illegible]	0	23,796	50,524
2021	51,463	25,976	77,430	6,414	17,767	0	24,181	53,249
2022	54,070	26,677	80,746	6,574	18,031	0	24,605	56,143
2023	56,836	27,403	84,239	6,717	18,296	0	25,014	59,224
Total 2014-23	[illegible]	244,[illegible]	[illegible]	[illegible]	171,[illegible]	0	[illegible]	479,107
RADR Rate	[illegible]	7.25%		7.40%	[illegible]	[illegible]		
NPV	163,376	61,697	[illegible]	12,701	[illegible]	43,778	[illegible]	119,417

Figure 9.3 Cost of Fossil-Fuel Receipts at Steam-Electric Plants
(Dollars per Million Btu)

Costs, 1973-1986



Costs, Monthly



Source: Table 9.10.

Table 9.10 Quantity and Cost of Fossil-Fuel Receipts at Steam-Electric Utility Plants

	Coal		Petroleum				Gas[a]		All Fossil Fuels[b]
			Heavy Oil[b]		Total[b,c]				
	Quantity (thousand short tons)	Cost (cents per million Btu)	Quantity (thousand barrels)	Cost (cents per million Btu)	Quantity (thousand barrels)	Cost (cents per million Btu)	Quantity (million cubic feet)	Cost (cents per million Btu)	Cost (cents per million Btu)
1973 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	47.6
1974 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	81.4
1975 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	104.4
1976 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	111.9
1977 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	120.7
1978 Year	[illegible]	111.6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	141.1
1979 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	160.9
1980 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	192.8
1981 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	225.6
1982 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	224.5
1983 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	220.6
1984 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	219.1
1985 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	208.4
1986 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	175.8
1987 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	170.8
1988 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	164.3
1989 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	167.5
1990 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	168.9
1991 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	169.3
1992 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1993 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1994 Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	152.6
1995 January	[illegible]	132.1	[illegible]	[illegible]	6,113	[illegible]	[illegible]	[illegible]	146.4
February	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	197.1	143.7
March	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	144.3
April	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	194.5	144.1
May	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	147.3
June	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	150.4
July	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	146.1
August	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	179.4	145.1
September	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	145.1
October	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	204.1	142.6
November	[illegible]	[illegible]	4,770	[illegible]	5,414	[illegible]	[illegible]	210.9	143.3
December	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	236.3	146.1
Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	145.3
1996 January	[illegible]	[illegible]	[illegible]	[illegible]	14,540	307.1	[illegible]	201.0	155.5
February	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	146.5
March	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	146.0
April	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	150.0
May	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	317.6	[illegible]	[illegible]	151.6
June	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	155.1
July	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	156.2
August	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	154.6
September	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	307.1	[illegible]	219.1	145.3
October	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	317,116	[illegible]	146.6
November	71,376	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	151.0
December	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	156.1
Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	151.9
1997 January	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	157.5
February	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	150.9
March	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	237.1	145.4
April	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	144.5
4 Months	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	149.5
1996 4 Months	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	317.0	[illegible]	[illegible]	[illegible]
1995 4 Months	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	144.4

[a] Includes supplemental gaseous fuels.
[b] Heavy oil includes fuel oil nos. 4, 5, and 6, and topped crude oil. The weighted averages for petroleum and all fossil fuels include both heavy and light oil (fuel oil nos. 1 and 2, kerosene, and jet fuel) prices. Data do not include petroleum coke.
[c] Data for 1973-1982 do not include small quantities of [illegible] motor oil, [illegible] oil, and liquefied petroleum gas.

Notes: • See Note [illegible] at end of section. • Geographic coverage is the 50 States and the District of Columbia.

Sources: See end of section.

10/7/97

Docket No. 981184-EQ
Exhibit No. _____ LGS-16

Cost Breakdown for Typical Combined Cycle Power Plant
250 Megawatt Capacity Plant

	Total Cost ($000)	Total Cost Percent
Mechanical	[illegible]	[illegible]
Electrical and Controls	[illegible]	[illegible]
Chemical	[illegible]	[illegible]
Civil, Structural and construction services	[illegible]	[illegible]
Total Construction Cost	[illegible]	[illegible]