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August 31, 2012

BY HAND DELIVERY

Ms. Ann Cole, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 120001-EI: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor

Dear Ms. Cole:

Enclosed for filing, please find the original and 15 copies of a Petition for Approval of Fuel Adjustment and Purchase Power Cost Recovery Factors submitted on behalf of Florida Public Utilities Company, along with the Direct Testimony and Exhibits CDY-4 through CDY-7 of Mr. Curtis Young. The Company is also submitting the same number of copies of the Direct Testimony and Exhibits RJC-1 through RJC-7 of Mr. Robert Camfield, and the Direct Testimony of Ms. Cheryl M. Martin. Also enclosed for filing is a copy of the schedule included in this filing on CD in native format.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

Sincerely,

Beth Keating

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 120001-EI DATED: August 31, 2012

FLORIDA PUBLIC UTILITIES COMPANY'S PETITION FOR APPROVAL OF FUEL ADJUSTMENT AND PURCHASED POWER COST RECOVERY FACTORS

Florida Public Utilities Company (FPUC or Company), by and through its undersigned counsel, hereby files this Petition asking the Florida Public Service Commission (FPSC or Commission) for approval of FPUC's fuel adjustment and purchased power cost recovery factors for the period January 2013 through December 2013. In support of this request, the Company hereby states:

1) FPUC is an electric utility subject to the Commission's jurisdiction. Its principal business address is:

Florida Public Utilities Company
1641 Worthington Road, Suite 220
West Palm Beach, FL 33409

2) The name and mailing address of the persons authorized to receive notices are:

Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe St., Suite 601 Tallahassee, FL 32301 (850) 521-1706	Cheryl Martin Florida Public Utilities Company 1641 Worthington Road, Suite 220 West Palm Beach, FL 33409

3) Consistent with the requirements for this proceeding, the Company has prefiled the fuel adjustment and purchased power cost recovery schedules supplied by the Commission consistent with the requirements for such filings, and have reflected therein the Company's calculated fuel adjustment factors for the Company's Northwest (Marianna) and Northeast (Fernandina Beach) divisions.

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4) In accordance with Order PSC-12-0061-PCO-EI, issued February 10, 2012, in this Docket, the Company is also submitting, contemporaneously with this Petition, the Direct Testimony and Exhibits CDY – 4, CDY-5, CDY-6, and CDY-7 of Mr. Curtis D. Young in support of the Company's request for approval of the requested factors.

5) The Company is also offering the Testimony and Exhibits RJC-1 through RJC-7 of Mr. Robert J. Camfield of Christensen & Associates in support of the Company's proposal to change the demand allocation methodology used by the Company.

6) The Company is further providing the Testimony of Ms. Cheryl M. Martin, which includes additional supporting information, particularly as it relates to recovery of legal and consulting fees associated directly with fuel-related projects that have produced savings for customers in the Company's Northwest Division.

7) As set forth in the Testimony and Exhibits of Mr. Young, the Company's total true-up amounts that would be collected or refunded during the period January 2013 through December 2013 are an under-recovery of $1,503,740 for the Marianna Division. Based on estimated sales for January 2013 through December 2013, an additional .45374¢ per kWh will need to be collected to address this under-recovery. With regard to the Fernandina Beach (Northeast) Division, the total true-amount is an over-recovery of $255,610, which equates to an amount of .07673¢ per kWh to be refunded during 2013. Pages 3 and 10 of Composite Exhibit Number CDY-4 provides the detailed calculations of the respective true-up amounts.

8) Based upon the Company's projections and the total true-up amounts to be collected for both Divisions, the appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2013 through December 2013, excluding demand cost recovery and adjusted for line loss multipliers and including taxes, are as follows:

Northwest Division (without Amendment No. 1/with revised Demand Allocation)

Rate Schedule	*Adjustment*
RS	$0.10478
GS	$0.09877
GSD	$0.09878
GSLD	$0.09464
OL,Ol1	$0.07842
SL1, SL2, and SL3	$0.07952
Step rate for RS	
RS with less than 1,000 kWh/month	$0.10119
RS with more than 1,000 kWh/month	$0.11119

Northeast Division (with revised Demand Allocation)

Rate Schedule	*Adjustment*
RS	$0.10203
GS	$0.09411
GSD	$0.09412
GSLD	$0.09084
OL	$0.06739
SL	$0.06719
Step rate for RS	
RS with less than 1,000 kWh/month	$0.09831

RS with more than 1,000 kWh/month	$0.10831

9) The total fuel adjustment factor for the Northwest Division is 6.149¢ per kWh and for the Northeast Division is 6.420¢ per kWh for "other classes." As a result, a customer in Marianna using 1,000 kWh will pay $137.35, an increase of $2.71 from the prior period. In the event that Amendment No. 1 to FPUC's Generation Services Agreement is affirmed by the Florida Supreme Court, the typical residential customer in the Northwest Division will pay $129.94, a decrease of $4.70 from the prior period.

10) With regard to the Northeast Division, a customer in Fernandina Beach using 1,000 kWh will pay $134.40, a increase of $5.33 from the prior period.

11) The Company has also adjusted the Time of Use (TOU) and Interruptible rates for the 2013 period. The Company submits that the methodology used to compute the rates reflected below is consistent with the methodology previously approved by the Commission.

Time of Use/Interruptible

Rate Schedule	*Adjustment On Peak*	*Adjustment Off Peak*
RS	$0.18519	$0.06219
GS	$0.13877	$0.04877
GSD	$0.13878	$0.06628
GSLD	$0.15464	$0.06464
Interruptible	$0.07964	$0.09464

12) The Company attests that these factors have been calculated correctly and consistent with Commission requirements. Thus, the Company asks that the Commission approve the proposed factors as set forth herein.

WHEREFORE, FPUC respectfully requests that the Commission approve the Company's proposed fuel adjustment and purchased power cost recovery factors and step billing for January 2013 through December 2013.

RESPECTFULLY SUBMITTED this 31st day of August, 2012.

Beth Keating
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215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

Attorneys for Florida Public Utilities Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been served upon the following by US Mail this 31st day of August, 2012.

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By: Beth Keating

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

Testimony of
Robert J. Camfield
(Allocation Methodology)
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Robert J. Camfield, and my business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

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

A. I hold the position of Vice President with Christensen Associates Energy Consulting.

Q. What is the purpose of your testimony?

A. My testimony is focused on two related topics. First, my testimony presents the results of a study that addresses the appropriateness of the use of load research results of Florida Power and Light (FPL) and Gulf Power Company (Gulf Power), for the purpose of allocation of the wholesale demand charges incurred by Florida Public Utilities Company to retail customer classes of its Northeast and Northwest Divisions respectively. Second, for the consideration of the Florida Public Service

Commission and Staff, the testimony advances modest yet important changes to Florida Public Utilities Company's (FPU, Company) current approach for allocation of wholesale demand charges to customer classes. The recommended changes to the current approach draw from the results and technical analyses reported in the study.

Q. Can you please provide a brief overview of your professional background?

A. Yes. The scope of my professional work is focused on the energy industry and includes cost of capital and valuation, regulatory economics, economic analysis, and cost allocation. For over thirty years, I have been involved in numerous technical and policy issues facing energy utilities including electric and gas utilities. In both formal evidentiary proceedings and less formal settings before regulatory authorities, I have made appearances on behalf of consumer advocacy groups, transmission and distribution companies, RTOs, integrated electric utilities, generation companies, regulatory agencies, and utility associations. I have provided testimony on a variety of topics including power supply contracts, transmission congestion, marginal costs and cost allocation, tariff design and rate phase-in plans, corporate performance and cost benchmarking, and load and energy forecasts. My consulting assignments include the management of power procurement solicitation, and wholesale market restructuring. I have contributed materials to noted industry journals such as *The Electricity Journal* and *IEEE Transactions on Power Systems*, and presented papers before the *Council on Large Electric Systems*. I served as Program Director for the Edison Electric Institute's *Market Design and Transmission Pricing School*, 1999–2008. I have held the position of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I hold a masters degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

Q. Have you previously testified in this Docket?

A. No, though I have filed testimony in fuel and non-fuel related dockets of the Florida Public Service Commission (Florida PSC) in previous years.

Q. Please provide background for the Company's proposed adjustments to the cost allocation methodology.

A. Under long-term contracts, the Company purchases generation and transmission services in wholesale power markets. The charges for purchased power and transmission services include energy and demand charges. In turn, the wholesale demand charges are allocated to retail customer classes. My testimony briefly describes the basis for the proposed fuel demand allocation computations that are used in the preparation of the various fuel projection schedules that the Company has submitted in support of the proposed January–December 2013 fuel cost recovery factors of the retail tariffs of the Company's two electric divisions, FPU Northeast and FPU Northwest.

Q. What are the Company's proposed adjustments to the method for allocation of demand charges recovered in retail fuel charges?

A. As mentioned above, FPU is proposing to incorporate modest but important modifications to the current approach to demand charge allocation, for the 2013 fuel rates. The proposed approach continues to utilize the Company's framework and structure of 2012 and earlier years, but with modified load factors. For 2013 forward, the proposed changes are threefold. First, the Company proposes to apply the load research results for the residential and business classes (GS, GSD, and GSLD) of Gulf Power to the Northeast Division in lieu of the corresponding load factors drawn from FPL's load research. Second, the load factor of Gulf Power's GSD class, also obtained from Gulf's load research, is applied to FPU's GS class in both the Northeast and Northwest Divisions. Third, the load factor estimated from Gulf Power's residential class is adjusted (increased) for FPU Northwest in order to account for clear differences in the residential load profile between the two utilities, driven by differences in economic and demographic conditions.

Q. To start, please describe the current demand allocation methodology used by Florida Public Utilities Company.

A. Currently, for FPU's Northeast and Northwest Divisions, the Company utilizes annual load factors obtained from the load research results reported to the Florida PSC. For the Northeast Division, FPU utilizes the load factors reported by FPL; for the Northwest Division, load factors are drawn from the load research reported by Gulf Power. Specifically, the two neighboring utilities report annual load factors, obtained through respective sample load research efforts, for each of the main customer classes including the Residential Class (RS) as well as main business classes, General Service (GS), General Service Demand (GSD), and Large General Service (GSLD), sometimes referred to as Large Power. The load factors reported by FPL and Gulf Power are assigned to the similarly defined customer classes of the Company's Northeast and Northwest Divisions respectively.

Q. Has not this approach worked acceptably well? What are the concerns that cause the Company to purpose an alternative methodology?

A. The Company has followed the current approach for several years. Since the Chesapeake acquisition, the Company has harbored concerns about the applicability of the load research results of FPL and Gulf Power to the retail electricity markets in the areas served by its Northeast and Northwest Divisions respectively. Retail class loads can be described in several ways, such as energy sales, seasonality of sales, peak loads, load factors, and load profiles sometimes referred to as load curves. Electricity class loads in turn are influenced by commonly recognized causal factors including weather patterns, household income and related demographic characteristics, employment, housing and building stock indicators, sector composition of the underlying regional economy, and the level of retail electricity prices.

Providing that key attributes of the FPL and Gulf Power service territories are sufficiently similar to the areas served by FPU's Northeast and Northwest Divisions, it is arguably appropriate to apply load research results of FPL and Gulf Power to FPU's electricity divisions, other factors constant. The Company's concerns can be succinctly expressed as two fundamental questions, as follows:

1) Are the economies, demographic characteristics, and weather patterns of the larger geographic areas of FPL and Gulf Power sufficiently similar to the areas served by the Company, insofar as load research results to a substantial degree reflect these causal factors?

2) If FPL and Gulf Power territories are found to be dissimilar from the areas served by FPU's Northeast and Northwest Divisions in important ways, what corrective actions are available in order to ensure that a fair cost allocation result across retail classes is achieved?

Essentially, should significant differences be found, it is necessary to consider alternative methods? For this reason, my testimony and accompanying exhibits as well as the supporting study (Study Report, Exhibit RJC-7), upon which the testimony is based, present a comparative assessment of key features of the regions—predominantly focusing on weather, economic, and demographic characteristics as well as supporting statistical analyses. This assessment is used to determine the structure of the proposed adjustments to the current method of demand charge allocation.

SUMMARY OF STUDY FINDINGS AND RECOMMENDATIONS

Q. Please summarize your testimony, including key findings of the Study Report to which you refer, and the proposed adjustments.

A. A summary of the findings contained in the Study Report and my recommendations are as follows:

For the Northeast Division: A comparison of weather patterns for the Northeast region and FPL's service territory is shown in Exhibit RJC-1, including two tables (Tables 2 and 3 of the Study Report). The first table presents heating degree days (HDDs) and the second table presents cooling degree days (CDDs). With the HDD's serving as a proxy for the demand for spatial heating, the heating loads of the two regions are likely to be remarkably different, with the heating loads for FPU Northeast (proxied by Jacksonville) 2.4 times that of the FPL region (1,350 HDDs vs. 554 HDDs). CDDs present similar though less dramatic differences: the cooling loads for the area served by FPU Northeast are 21% less than the corresponding loads for the FPL region, using the Jacksonville proxy (3,392 CDDs vs. 2,664 CDDs). Recognizing that the weather for Fernandina Beach suggests somewhat less variation, substantial differences in weather patterns are present. The variation is particularly important for the Northeast insofar as peak demands driving demand charges are specific to month regardless of season. Thus, winter weather differences matter.

It is not surprising to find that, in contrast, the comparison of weather patterns (HDDs, CDDs) for the FPU Northeast and Northwest Florida regions reveal remarkably similarity. The annual average HDDs for Jacksonville (JAX) and Fernandina Beach (F B) are 1,350 and 1,215, respectively, while Pensacola (PEN) is 1,537. Cooling demands are also similar, with 2,664 and 2,803 for Jacksonville and Fernandina Beach respectively; and 2,609 for Pensacola. Also, weather data for other locales in northern Florida paint a similar picture.

In brief, because weather is the major determinant of the level and profile of class loads, it is appropriate for FPU to consider the use of the load research results of Gulf Power for demand charge allocation for the Northeast Division, as opposed to the load research results of FPL.

For the Northwest Division: The analyses include a comparison of economic indicators and demographic characteristics of the region served by FPU's Northwest Division with respect to Gulf Power. The comparison focuses primarily on housing stock and economic indicators, and the implications for the underlying load factor. Summary results are shown in Exhibit RJC-2, and are further supported by a series of tables incorporated within the body of the Study Report (Report Tables 8, 11–12 and 14). For the Northwest Division and Gulf Power, pages 1 and 2 of Exhibit RJC-3 present a comparison of the housing stock and economic measures including household income and the incidence of poverty. Additionally, page 2 of the same Exhibit presents a comparison of the age distribution and household type, measured in terms of the proportion of elderly (aged 65 and above) living alone. The main finding is, predominantly because of comparatively low levels of household incomes, much higher shares of the housing stock in the Northwest area are mobile homes and older vintage stationary dwellings, when compared to the Gulf Power region.

Mobile and older vintage homes have a much higher saturation of window air conditioning (A/C) units for spatial cooling than more contemporary stationary homes. Because of the cycling patterns inherent to window A/C units, the residential load profile for the Northwest Division is significantly less sensitive to changes in summer temperatures during very high temperature, peak load days. This conclusion is reinforced by two types of statistical analyses contained in our Study Report (Section III.B and III.C of the report), which assess the relationships between loads, temperature and residential energy shares. The first analysis applies regression methods to determine the relationships between daily peak loads and a temperature index, and confirms the declining impact of temperature on peak loads. In other words, we find that the sensitivity of hourly system loads of the Northwest Division to be significantly less, during summer top load days than during less than the highest load days. For the Northwest Division, the sensitivity of loads to temperatures rises as progressive lower load days are incorporated into the analysis sample. Further details regarding the methodology and findings are provided later on in this testimony (named Statistics 1-Based Analysis). A snapshot of the main results of this analysis is shown on page 1 of Exhibit RJC-3.

The second analysis using regression methods to estimate the relationship between the weather-normalized system load factor and the residential class share of total energy share, for the Northwest Division. This second analysis finds that, as expected, a decrease in residential energy share within the total sales of Northwest increases (improves) the system load factor. This result is fully consistent with expectations: because the load factor of the residential class is above that of the Northwest system as a whole, decreases in the residential energy causes the system load factor to rise, a result that is confirmed by real world experience over recent years. The main results of this analysis are shown on page 1 of Exhibit RJC-4. Further details regarding the methodology and findings are provided later on in this testimony (referred to as Statistics 2-Based Analysis). In brief, the conclusion reached from the demographic and housing stock differences shown on Exhibit RJC-2 between FPU Northwest Division and Gulf Power have, historically, likely resulted in an overstatement of peak demand impacts attributable to the residential customer classification under the current demand allocation method. Thus, I believe that certain modifications to the Gulf Power Load Research data for demand allocation is appropriate.

RECOMMENDED ADJUSTMENTS TO COST ALLOCATION METHOD

Q. Please detail the proposed adjustments to the Company's cost allocation methodology.

A. In view of the above findings, reached from the comparative and statistical analyses contained in the Study Report. I propose that certain adjustments be incorporated into FPU's current framework for the allocation of wholesale demand charges. The recommendations are as follows:

Load Research of Gulf Power Applied to the Northeast Division: As discussed above, because of similar weather patterns of the underlying regions of these utilities, the load research results of Gulf Power are likely to be a better match to the Company's Northeast Division than the currently used load research of FPL. Consequently, I recommend using the load research results of Gulf Power as the basis for allocation of demand charges, for the Northeast Division.

Load Research Results of Gulf Power's GSD Class Assigned to GS Class, FPU Northeast and Northwest Divisions: For the main customer classes of the two divisions of FPU and Gulf Power, pages 1 and 2 of Exhibit RJC-5 presents calculations of average monthly energy, for months with low shares weather sensitive loads (March, April, and

November) and months with higher shares of weather sensitive months. Weather sensitive months are grouped into summer and winter groups. The tables present the ratios of the weather sensitive loads to the loads for low weather sensitive months. The analysis is presented for the Northeast and Northwest Divisions, each of which is compared to Gulf Power. As shown, for summer months of both Divisions, the ratio of weather sensitive to non-weather sensitive monthly energy for Gulf Power's GSD class is a better match to FPU's GS class than Gulf Power's GS class. This change in the assignment of Gulf Power's class load research results to FPU is important insofar as differences in weather sensitive loads have inverse though non-linear effects on load profiles and the estimated class load factors (effects are differentiated between summer and winter seasons). Accordingly, I recommend that Gulf Power's GSD load factors be assigned to the GS class, for both the Northeast and Northwest Divisions.

Adjustment to the Residential Load Factor, Northwest Division: As mentioned above, the residential class of the Northwest Division has high shares of mobile and older stationary homes within the housing stock. Because of the resulting high concentration of window air conditioners, the share of total monthly energy determined by the demand for spatial cooling (A/C loads) is comparatively small during summer months—

particular peak load days—when compared to Gulf Power. This result, as demonstrated by the ratio of weather to non-weather sensitive monthly energy ratios (above), as well as the statistical analysis outlined earlier in the testimony affirms that an adjustment is in order. The proposed adjustment mechanism results in a 2.557 MW reduction in the implied coincident peak demand for the residential class for the Northwest Division, approximately 7–8%. Arguably, the analyses contained in the Study Report suggest this proposed adjustment amount is somewhat conservative.

Q. As you mention, the Study Report appears to demonstrate that the weather of the regions served by FPU Northeast and FPL are not well matched. Please discuss in detail, focusing on why Gulf Power load research is better matched to the Northeast.

A. Exhibit RJC-1 discussed above reveals exceptionally high similarity in the weather patterns of FPU (Jacksonville and Fernandina Beach) and Northwest Florida, with Pensacola serving as an appropriate proxy for Gulf Power. We could, of course, incorporate within our Study Report the historical weather experience (HDDs and CDDs) for other locations across Florida's northern tier; results show further similarity. To conclude, the weather locales of the northern tier including areas served by Gulf Power are much better matched to the Northeast Division. The recommendation—use Gulf Power's load research results—logically follows.

I should mention that, generally speaking, county-population weighted economic and demographic indicators of FPL and Gulf Power appear to be similar, with both regions somewhat differentiated from Nassau County, located in northeast Florida, though such a comparison is not incorporated within the Study Report. However, we infer that, for these comparison metrics, Nassau county may not be a particularly good proxy for FPU's Northeast Division.

Q. Your comparative analysis of the underlying economies of FPU's Northwest Division and Gulf Power summarized above suggest major differences. Please elaborate.

A. The comparative analysis detailed in the Study Report has major implications for the levels and profiles of residential loads, as mentioned. We were initially surprised by the magnitude of the differences in the underlying economic indicators and demographic characteristics, particularly in view of the reasonably close proximity of much of Gulf Power's region to the counties served by FPU Northwest. It is thus appropriate to fully discuss how these differences, including household income, housing stock, employment, incidence of poverty, age composition, and educational attainment, translate into load differences between the residential classes for the Northwest and Gulf Power.

As affirmed by the statistical analysis, discussed below in detail (Section III.B of the Study Report), we find that these differences contribute to, and will likely cause, systematic bias in the estimates of residential peak demands for the Northwest Division, if unadjusted residential load factors, obtained from Gulf Power load research, are applied to the residential energy consumption of the Northwest Division. On this point, quantitative evidence is presented in pages 1 and 2 of Exhibit RJC-2, mentioned above. In particular, households in the Northwest have some three times the percentage share of mobile homes as households in the region served by Gulf Power. Moreover, the survey data are confirmed by direct observation, and is consistent with, and supported by, the larger share of comparatively low income households within the Northwest.

The implication is a truncated peak load-to-average energy ratio for FPU Northwest residential customers, as mobile homes predominantly use window A/C. Experience analyzing loads and temperatures provide the basis to infer the underlying reasons for the attenuated impacts of residential loads for the Northwest Division at very high levels of summer temperatures. First, window A/C units typically provide only compromised capability to manage exceptional temperatures, whereas central A/C units tend to be installed with capacity that approximates or exceeds expected maximum requirements. As a consequence, window A/C units will typically run up against constraints on output levels well before the peak hours on the hottest days. Conversely, central A/C units of stationary homes are often oversized; the spare capacity implies that usage continues to climb with temperatures, rather than reaching a plateau. Hence, loads on peak temperature days for window units are typically not much higher than the peak usage on cooler days.

Second, with central A/C, peak days lead to substantially higher loads when the A/C is 'over-designed', especially since unit efficiency tends to decline as temperatures increase. Third, households with central A/C units tend to be programmed to increase the cooling levels prior to residents returning home during week days, leading to more cooling demand during the peak hours of power systems, and less in the periods immediately before and after the peak hours. Fourth, single individual households (living alone and "at home" during mid-day hours) will tend to have reduced differences between average and peak hour loads during peak temperature days. As shown within the Study Report as well as in Exhibit RJC-2, the Northwest Division has a higher share of residential customers that are both older and living alone.

Q. Earlier, you indicated that the change in the estimated coincident peak demand for the residential class of the Northwest Division should be adjusted downward by 2,557 kW. How is this adjustment obtained?

A. The adjustment amount of 2,557 kW is obtained from the estimates obtained through statistical analyses including, for the Northwest Division, the regression analysis of: 1) daily system peak summer loads on temperatures, and 2) weather-normalized system load factor on residential energy shares. These two analyses, referred to as Stats 1 and Stats 2, respectively, are described in some detail within the Study Report (Sections III.B and III.C respectively of Exhibit RJC-7). The estimated equation from the Stat 1 analysis is presented on page 1 of Exhibit RJC-3; the Stat 2 equations are presented on page 1 of Exhibit RJC-4.

Statistics 1-Based Analysis: The overall findings from the comparative assessment of the Northwest Division and Gulf Power regions suggested that there is likely to be a greater prevalence of window air conditioner (A/C) units across FPU Northwest customers than within the Gulf Power residential class. The implication is a truncated peak load-to-average energy ratio for FPU Northwest customers, which can be seen in a plot of loads against temperature, which unequivocally demonstrates concavity toward the top end of the load-temperature function. This declining impact of temperature on peak loads has been substantiated by regression analysis of the daily peak load for FPU Northwest on an index of daily temperatures, plus three sets of binary variables for the maximum hour of the day, year and the beginning and end of the week. The analysis uses data for 11 years (1999–2010, excluding 2005), and the data is sorted in two ways, by temperature index and maximum usage (we primarily use the results of the maximum usage regressions). Regressions were run on the top 100 load days, the top load 200 days, and so on, till the top 1100 load days (the full sample). The analysis is discussed in some detail within the Study Report (Section III.B), and the regression specification is shown on page 1 of Exhibit RJC-3. Key results are shown on pages 1 and 2 of Exhibit RJC-3.

The main result of this analysis (from page 1 of Exhibit RJC-33) is that the slope (gradient) defined as, load change with respect to a change in temperature, is higher at temperatures that are less than the highest temperatures. This clear concavity in the relationship between peak loads and temperature is typical of window A/C units, which reach their maximum cooling capacity prior to reaching peak temperatures. This is consistent with the supposition of the greater prevalence of window A/C units among FPU Northwest residential customers. In light of this finding, we find that it is highly likely that, in the absence of appropriate adjustments, the use of Gulf Power load research will overstate the peak demand responsibility of FPU Northwest's residential customers.

The analysis procedures used to determine estimates of the differential in system peak demand attributed to the residential class of the Northwest Division is contained in page 2 of Exhibit RJC-3. Column 1 of the first table on page 2 presents the *total* estimated peak load (intercept plus the sum of the estimated slopes (coefficients) times the mean value of the respective variable), controlling for *all* variables, for the five selected models. For example, the total estimated peak load is 67,451 kW for the top 100 model. The other columns compute the estimated load based on the effects of each explanatory variable, holding all other effects constant. For example, for the top 100 model, the estimated load with respect to a given temperature and temperature slope is 1,897.8 kW, controlling for all else. The second table on page 2 of this Exhibit presents the estimated loads with respect to temperature effects. Aggregating the partial estimated loads in the first table gives us the total estimated load, for each model.

The load impacts attributed to the residential class can be gleaned from the third table on page 2 of Exhibit RJC-3.

(1) The first kW differential is the difference in the estimated system peak demand between the Top 100 Loads Model and the average of estimated system peaks for the Top 600–1,100 Loads Models (using the first table on page 2 of Exhibit RJC-3).

(2) The second kW differential is the difference in the estimated system peak demand using the estimated temperature coefficients for the Top 100 Loads Model, and the average of the estimated coefficient for the Top 600–1,100 Loads Models (using the second table on page 2 of Exhibit RJC-3).

Then, the average kW differential (average of 1 and 2) is -2,638 kW, as obtained from Stat-1 analysis.

Statistics 2-Based Analysis: The Stat 2 regression model is used to estimate the change in the weather normalized system load factor with respect to the change in residential energy shares, for FPU Northwest. Details on the computation of weather-normalized load factors are contained in Footnote 15 of the main report (Exhibit RJC-7). This analysis is based on time series data, for the five summer months over 2001–2009 (2005 is excluded because of missing load data) and is discussed in some detail within the Study Report. Key results are shown on pages 1 and 2 of

Exhibit RJC-4.

As discussed, the regression model specifies the load factor as a linear function of the residential energy shares (the main variable of interest), the real price of electricity, and four binary variables for the summer months of May through August (September is the base category). The objective is to estimate the sign and magnitude of the coefficient of the shares variable. In so doing, the effect of changes in the residential energy share on load factor, if it exists, is determined. As discussed earlier (as well as seen in Column 1 of the table on page 1 in Exhibit RJC-4), the relationship between the weather normalized system load factor and residential energy, for summer months, is negative and statistically significant; a residential share decrease of 1% translates into a system load factor increase of 0.723%.

The Stat 2 model also provides an estimate of the change in the weather normalized system load separately for two time periods, namely 2001–2007 and 2008–2009. This provides a basis to determine the incremental impact (decrease) occasioned by the change in the reduced residential energy and thus peak loads, from 2008 onwards. In order to implement this, we estimate the original model inclusive of a binary variable for the 2nd period (2008–2009), and interact the share variable with the newly introduced binary (2001–2007 is the base category). The results in Column 2 of the table on page 1 in Exhibit RJC-4 show that for both periods, residential energy share remains negative and significant, and is of a higher magnitude as compared to the previous model specification. Specifically, the coefficient on the shares variable provides the effect for the period 2001–2007 (a nearly two-fold impact of shares on load factor). The sum of the coefficients on the shares variable and the interaction dummy gives us the total effect for 2008–09, an effect of magnitude –1.603. These results provide evidence in favor of the fact that reductions in monthly residential energy shares are highly likely to be associated with equivalent reductions in the residential peak load class shares.

The increase in system load factor associated with declining residential energy shares translates into a reduction of 2,822.2 kW in the residential peak load (shown as Delta kW in the second table on page 2 in Exhibit RJC-4). In conclusion, the Statistic 1-based analysis results in a reduction of 2,638 kW in the residential peak load, while the Statistic 2-based analysis results in a reduction of 2,822.2 kW. I, therefore, recommend that for conservative purposes, the Company reduce the residential coincident peak demand by 2,557 kW, a result which is drawn from the above-cited statistical methods.

<u>DETERMINATION OF DEMAND CHARGES, NORTHWEST DIVISION</u>

The proposed adjustment to the residential peak demand of the Northwest Division shown in Exhibit RJC-6 is incorporated into the Company's current framework for allocation of wholesale demand charges. The procedure involves two steps. First, the coincident peak demand for the residential class is estimated under the current approach, which utilizes the residential class load factor (0.5731) reported in Gulf Power's load research to the FPSC. Given projected residential annual energy for 2013, the residential coincident peak demand is calculated. This result is adjusted downward by the amount of estimated bias in the coincident demand obtained for the residential class of the Northwest Division. The adjustment for bias, in the amount of 2,557 kW, is subtracted from the residential coincident peak demand. The second step involves the calculation of the effective load factor (0.6290), and is a direct result from the projection of sales for 2013 and the adjusted peak demand. The calculation is shown on Exhibit RJC-6, page 2.

Q. Does this conclude your testimony?

A. It does.

Heating Degree Days (HDDs) for Weather Zones
Served by FPU Northeast (F B and JAX), FPL and PEN[1]

Zone	J	F	M	A	M	J	J	A	S	O	N	D	Total
Zone 2	380	270	153	43	2	0	0	0	0	31	141	314	1333
Zone 3	271	195	99	22	0	0	0	0	0	8	74	207	876
Zone 4	202	146	72	13	0	0	0	0	0	3	47	148	631
Zone 5	130	96	36	6	0	0	0	0	0	0	20	86	374
Zone 6	90	66	24	2	0	0	0	0	0	0	9	52	243
FPL Avg.	178	129	60	12	0.2	0	0	0	0	5	42	128	554
JAX	380	257	156	55	5	0	0	0	0	28	145	323	1350
F B	358	252	145	40	3	0	0	0	0.	16	109	292	1215
PEN	429	297	176	51	2	0	0	0	1	37	174	370	1537
Miami	53	26	11	1	0	0	0	0	0	0	3	34	128

Cooling Degree Days (CDDs) for Weather Zones
Served by FPU Northeast (F B and JAX), FPL and PEN

Zone	J	F	M	A	M	J	J	A	S	O	N	D	Total
Zone 2	12	15	47	117	302	443	512	503	393	191	57	17	2607
Zone 3	24	33	76	155	330	460	523	518	441	277	104	42	2983
Zone 4	42	56	112	186	358	476	531	537	466	315	144	68	3291
Zone 5	64	84	131	205	354	463	522	534	480	366	186	103	3490
Zone 6	93	111	175	250	393	484	538	550	501	409	233	136	3870
FPL Avg.	57	72	123	197	356	468	527	533	468	338	166	88	3392
JAX	11	18	54	113	288	449	536	521	396	197	61	21	2664
F B	10	14	49	121	313	462	546	530	426	236	76	21	2803
PEN	6	8	33	101	300	465	533	521	403	180	46	13	2609
Miami	151	171	247	324	463	532	592	595	537	460	300	203	4575

[1] *JAX* refers to Jacksonville. *F B* refers to Fernandina Beach, which is clearly the preferred location to gather weather data for FPU Northeast as a matter of proximity. We utilize Jacksonville because its weather data is available hourly, and some of the analysis are conducted in frequency. Hourly data are not available for Fernandina Beach. *PEN* refers to Pensacola Regional Airport, the primary station for Pensacola, which is representative of the western end of the service territory for Gulf Power.

Housing Characteristics

Home Feature	FPU Northwest	Gulf Power Company
Mobile Homes	28.9%	9.3%
Homes built after 1990	27.7%	36%
Renter occupied homes	23.0%	32.1%

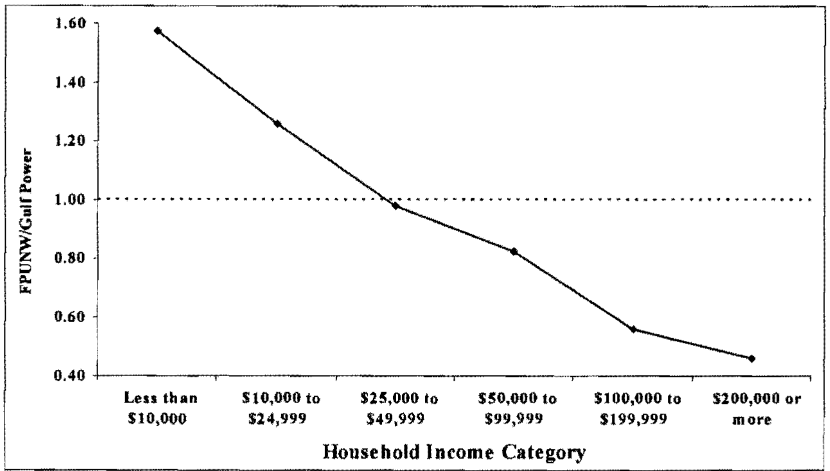
Per Capita and Household Income

Income Metrics	FPU Northwest	Gulf Power Company
Per Capita Income	$17,010	$25,315
Median Income Family	$48,778	$57,816
Median Income Household	$37,915	$48,252

Household Income Distribution

Income Category	FPU Northwest	Gulf Power Company
Less than $10,000	11.0%	7.0%
$10,000–$24,999	21.3%	16.9%
$25,000–$49,999	27.2%	27.8%
$50,000–$99,999	26.8%	32.5%
$100,000–$199,999	7.3%	13.1%
$200,000 or more	1.2%	2.7%

Household Income Distribution (Ratio of Shares)



Incidence of Poverty

Population Below The Poverty Line	FPU Northwest	Gulf Power Company
Families	11.5%	10.0%
Population	19.5%	13.5%
Below 18 years of age	16.8%	16.7%
Above 65 years of age	16.3%	8.6%

Age Distribution of Population and Household Type

Age Group	FPU Northwest	Gulf Power Company
Median Age	39.9	37.8
19 years and less	23.1%	25.8%
20–24 years	6.9%	7.8%
25–44 years	27.3%	25.8%
45–64 years	27.6%	26.8%
65 years and more	15.0%	13.7%
Household Type	**FPU Northwest**	**Gulf Power Company**
Aged 65 and living alone	11.8%	9.5%

STAT-1 MODEL:
Regression of System Peak Loads on Temperatures

Load-temperature model is as follows:

$$kW_d^{max} = \beta o + \beta_{Temp} TempIndex_d + \sum_h \beta_h Hour_{h,d} + \sum_y \beta_y Year_{y,d} + \sum_i \beta_i D_{i,d} + \varepsilon_d$$

Binaries include three sets of variables:

Hour of the maximum of the day, $Hour_{h,d}$, h = 14, 15, and 16 (with all the remaining hours grouped together as the baseline);

Year y, $Year_{y,d}$, y = 1999-2010 (excluding 2005); and

Beginning and End of Week D_i, i = Monday, Friday; beginning and end of week days are identified because these two days (especially Fridays) have comparatively lower loads, other factors held constant.

ESTIMATED MODEL:[2]
Coefficients for Load-Temperature Regressions
(Shown are coefficients for the variables)

		Day	Hours	Year Groups				
Group	Temp Index	Friday	14–16	1999–2001	2002–2004	2006–2007	2008	2009–2010
Top 100	795	–1663	993	–737	288	4974	2372	4
Top 200	891	–1372	870	–165	2783	7334	4702	2109
Top 300	960	–1577	1802	109	2892	7662	4184	2327
Top 400	1082	–1499	1727	390	3208	8260	4635	2594
Top 500	1077	–1403	1831	562	3149	8548	5089	2935
Top 600	1184	–1420	1763	409	3191	8761	4998	2860
Top 700	1247	–1419	2264	345	3119	8794	4976	2668
Top 800	1362	–1544	2316	563	3610	9083	5364	2834
Top 900	1420	–1559	2202	760	3842	9417	5598	2790
Top 1000	1478	–1609	2230	885	3750	9603	5857	2881
Top 1100	1561	–1655	2607	1201	3821	9942	6152	3063

[2] Sorted by Max kW.

STAT-1 MODEL:
Application of the Load-Weather Model Set to Estimate the Adjustment to Residential Peak Load

Full Model-Based Analysis

SYSTEM PEAK LOAD (Dependent Variable)		Hr16	Hr15	Hr14	T Index	Fri	Mon	Yr's	Yrs '00- '09	Bo
Top 100 Model	67,451	0.0	611.1	0.0	1,897.8	0.0	0.0	-189.2	0.0	65,131.8
Top 400 Model	64,713	0.0	0.0	525.3	2,581.4	0.0	0.0	2,204.8	0.0	59,401.1
Top 600 Model	64,295	0.0	0.0	558.4	2,824.0	0.0	0.0	2,440.4	0.0	58,472.5
Top 800 Model	63,444	0.0	0.0	715.0	3,249.9	0.0	0.0	2,272.1	0.0	57,206.9
Top 1100 Model	62,895	0.0	0.0	748.3	3,725.8	0.0	0.0	2,464.2	0.0	55,957.2

Coefficienjts Only-Based Analysis Results

Model	Beta, T.	T.Index	Estimated System Peak Load Effect of Temperature
Top 100 Model	795	2.3861	1,898
Top 400 Model	1,082	2.3861	2,581
Top 600 Model	1,184	2.3861	2,824
Top 800 Model	1,362	2.3861	3,250
Top 1100 Model	1,561	2.3861	3,726

Stat-1 Analysis Results: Load Impacts Attributed to Residential Class, Northwest Division

Estimated kW Differential	
-3,907	(Full Model-Based Estimates)
-1,369	(Coefficients Only-Based Estimated)
-2,638	(Average of Estimation Methods)

Note: Top 400 Model is not incorporated into the Average

Statistical Analysis 2:
Regression of System Load Factor on Residential Energy Share

Load factor-residential shares models are as follows:

$$LoadFactor_{m,y} = \beta o + \beta_{share} ResiShare_{m,y} + \beta_{price} Price_{m,y} + \beta_i D_i + \varepsilon_{m,y} \qquad \text{Model 1}$$

$$\begin{aligned} LoadFactor_{m,y} = {} & \beta o + \beta_{share} ResiShare_{m,y} + \beta_{price} Price_{m,y} + \beta_i D_i \\ & + \beta_{0809} D_{2008\text{-}09} + \beta_{share0809} (ResiShare_{m,y} \times D_{2008\text{-}09}) \\ & + \beta_{shareDi} (ResiShare_{m,y} \times D_i) + \varepsilon_{m,y} \qquad \text{Model 4} \end{aligned}$$

Variables are:

- $LoadFactor_{m,y}$: Weather-adjusted load factor in month *m* and year *y*
- $ResiShare_{m,y}$: Residential energy share of total sales for month *m* and year *y*
- $Price_{m,y}$: Real price of electricity for month *m* and year *y*
- $D_{2008\text{-}09}$: Binary variable for the years 2008-09. 2001-2007 (excluding 2005) is the base category.
- *Seasonal Patterns:* D_i represents four binary variables *(i = May, June, July, August)* covering summer months in order to control for systematic variation across the summer season. September is the base category.
- The term $\varepsilon_{m,y}$ is the error term for each month-year combination, representing all unspecified determinants of load factor.

In each of the above models, the coefficient of each month dummy, β_i, implicitly captures the difference in estimated intercepts between that month and the base period.

In Model 4, β_{share} captures the effect of the residential energy share on load factor for the base period 2001–2007. The corresponding effect of residential energy shares for the second period is captured as (β_{share} + $\beta_{share0809}$). Essentially, $\beta_{share0809}$ is the estimate of the *change* in the slope of residential energy share on load factor between these two time periods.

Variables	**Coefficient, (*t*-statistic)**	**Coefficient, (*t*-statistic)**
Residential Energy Share	-0.723 (2.06)	-1.760 (3.16)
Share x $D_{2008\text{-}09}$		0.157 (0.34)
Combined effect		-1.603 (2.28)
$D_{2008\text{-}09}$		-0.09 (0.49)
Price	-0.28 (1.48)	-0.32 (0.83)
Intercept	0.98 (5.93)	1.41 (5.56)
May	-0.06 (4.55)	-0.59 (1.97)
June	-0.04 (4.19)	-0.59 (2.02)
July	0.04 (3.82)	-0.30 (0.82)
August	0.02 (1.77)	-0.79 (2.17)
Adjusted R-Squared	0.696	0.730
Significance Level of *F*-statistic (40 Obs)	1.73×10^{-8}	5.59×10^{-7}

1. Values shown in parentheses refer to *t*-statistics associated with the estimated coefficients.

2. Dependent variable is the weather-normalized, monthly system load factor.

3. September is the omitted month within the set of monthly binary variables.

4. *F*-statistic refers to the degree of significance, defined as the lowest level at which the null hypothesis that the set of explanatory variables fail to 'explain' variation in the dependent variable can be rejected.

Determination of Demand Change Allocation
STAT 2 Model

Case	Changes From Base Case In:		Ratio: ΔSystem LF/ ΔShare
	Residential Share	System Load Factor	
Case 1	–2%	–1.19%	0.60
Case 2	–2%	0.30%	–0.15
Case 3	–2%	1.38%	–0.69
Case 4	–2%	3.21%	–1.603
Case 4'	–2.38%	3.82%	–1.603

Changes in Residential Peak Load as Load Factor Increases			
kW @ 57.31% LF	28,804.6	Average load	16907.2
kW @ 63.54% LF	25,982.4	Average load	16907.2
Delta kW	–2,822.2		

Comparative Analysis of Weather Sensitive and Non-Weather Sensitive Monthly Energy Northeast Division, Gulf Power

	FPU Northeast		Gulf Power	
Residential	**S**	**W**	**S**	**W**
'01 - '10	1.44	1.23		
'00 - '11	1.48	1.27	1.60	1.29
GS	**S**	**W**	**S**	**W**
'01 - '10	1.30	1.11		
'00 - '11	1.31	1.13	1.43	1.18
GSD	**S**	**W**	**S**	**W**
'01 - '10	1.24	1.05		
'00 - '11	1.25	1.06	1.35	1.08
GSLD	**S**	**W**	**S**	**W**
'01 - '10	0.99	1.04	1.23	1.07
'00 - '11	0.99	1.03	1.21	1.03

Notes:

1) "S" refers to Summer; "W" refers to Winter.
2) Ratios for Gulf Power calculated from data shown in Gulf Power's MFR Schedules, Docket EL 110138.
3) For Gulf Power, GSLD includes LP (upper set) and LPT (lower set) classes.

Comparative Analysis of Weather Sensitive and Non-Weather Sensitive Monthly Energy Northwest Division, Gulf Power

	FPU Northwest		Gulf Power	
Residential	**S**	**W**	**S**	**W**
'01 - '10	1.33	1.31		
'00 - '11	1.36	1.34	1.60	1.29
GS	**S**	**W**	**S**	**W**
'01 - '10	1.29	1.14		
'00 - '11	1.31	1.16	1.43	1.18
GSD	**S**	**W**	**S**	**W**
'01 - '10	1.27	1.09		
'00 - '11	1.27	1.10	1.35	1.08
GSLD	**S**	**W**	**S**	**W**
'01 - '10	1.23	1.08	1.23	1.07
'00 - '11	1.23	1.08	1.21	1.03

Notes:

1) "S" refers to Summer; "W" refers to Winter.
2) Ratios for Gulf Power calculated from data shown in Gulf Power's MFR Schedules, Docket EL 110138.
3) For Gulf Power, GSLD includes LP (upper set) and LPT (lower set) classes.

Load Factors and Demand Charge
Allocation Results for Northeast and Northwest Division

	Load Factor	
	Current*	Proposed
Northeast Division		
Residential	0.57599	0.57313
GS	0.75719	0.73904
GSD	0.78538	0.73904
GSLD	0.77959	0.84022
Northwest Division		
Residential	0.57313	0.62896
GS	0.63216	0.73904
GSD	0.73904	0.73904
GSLD	0.84021	0.84021
* Approved for 2012 Fuel Charges		

Determination of the kW Adjustment to Coincident Peak Demand and Load Factor, Residential Class of the Northwest Division

Coincident Peak Demand Adjustment (kW)

Analysis Basis	Analysis Result (Change in kW)
Stat-1	-2,638 kW
Stat-2	-2,822 kW
Proposed Adjustment	-2,557 kW

Note: Preliminary Study Report incorporated a -2,500 kW adjustment level, obtaining a 62.90% load factor, based on 2012 data. The -2,557 kW result shown above is equivalent to the adjustment amount for 2012 (–2,500 kW) factored for the expected change in the residential class sales for 2013, with respect to 2012. The result is to hold the proposed load factor constant.

Calculation of the Load Factor

Method

Step 1: Coincident $Peak^{Rs}_{Original\ Method}$ = $Sales^{Rs}$ /($LF^{Rs}_{GulfPower}$*8760)

Step 2: Coincident $Peak^{Rs}_{Adjusted}$ = Coincident $Peak^{Rs}_{Original\ Method}$ + kW Adjustment

Step 3: Corrected Load $Factor^{Rs}$ = $Sales^{Rs}$ /(Coincident $Peak^{Rs}_{Adjusted}$*8760)

Application for 2013

Step 1: 28,804.6 kW = 144,617,000 kWh /(0.57313 *8760)

Step 2: 26,247.6 kW = 28,804.6 kW+ (-2,557 kW)

Step 3: 0.6290 = 144,617,000/(26,247.6*8760)

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Inferred Class Contribution to Peak Loads for Allocation of Wholesale Demand-Related Costs Incorporated In Retail Fuel Charges

prepared for:
Staff of the Florida Public Service Commission
and
Electric Division, Florida Public Utilities Company

prepared by:
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J. David Glyer
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August 29, 2012

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REPORT

INFERRED CLASS CONTRIBUTION TO PEAK LOADS FOR ALLOCATION OF WHOLESALE DEMAND-RELATED COSTS INCORPORATED IN RETAIL FUEL CHARGES

prepared for:
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and
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August 29, 2012

I. BACKGROUND

This report is focused on methods to infer the customer class contribution to peak loads, in the absence of estimated class load shapes specific to Florida Public Utilities Company (FPU, Company). The report responds to concerns expressed during the January 19, 2012 on-site discussion between the Staff of the Florida Public Service Commission (Staff) and FPU.

During the January meeting, Staff provided comments about FPU's revised approach, as proposed, for allocation of wholesale demand charges to the four classes of retail customers served by the Company. The concerns of Staff (i.e., Division of Economic Regulation) were previously identified in Staff's November 14 memorandum to the Florida PSC, Docket 110001-EI, as follows:

> FPUC stated in its brief that the CA [Christensen Associates] report trended customer consumption patterns over a ten year period. (FPUC BR 6) However, there is no showing in the CA report that a reduction in

> overall energy consumption translates into reduced demand during the system peak...CA also studied price elasticities for each division and developed models for gauging energy consumption with respect to changes in several variables, including price, weather, and income. (FPUC BR 6)...The CA report's regression analysis...appears appropriate, but...does not show how the results of the analysis is related to peak demand...In response to staff discovery, FPUC responded that the load shapes for classes of customers served by other utilities may not readily fit FPUC because of a) differences in gas saturation, b) differences in temperature patterns, c) differences in class definitions, d) differences in the economic sector of commercial/industrial customers served, e) differences in rate levels and rate design, and f) differences in income and employment levels...FPUC's reliance on FPL and Gulf actual load research has been accepted for many years. Staff also agrees with FPUC that there is no evidence in the record of this proceeding that indicates whether FPL and Gulf are appropriate load proxies for FPUC. (TR 378)

As Staff indicated, the Report[1] by Christensen Associates Energy Consulting, dated September 7, 2011, and referenced above, did not fully address the immediate issue at hand: are class load factors obtained from load research samples of other Florida utilities, including Florida Power and Light (FPL) and Gulf Power Company (Gulf), suitable for use by FPU to infer the contribution to peak demand (peak load share) of the customer classes of FPU? In the absence of a load research sample specific to FPU customers, what other methods might be available?

We generally concur with Staff's view. This follow-up report approaches these two issues by analyzing economic, demographic, and weather data and related information. The report provides a comparative assessment of FPU's electricity markets with respect to those of FPL and Gulf, and includes statistical analysis of load factors, energy shares, and weather. The similarities and differences of the relevant regions (FPL, FPU, and Gulf) are highlighted along these three dimensions (economic, demographic, and weather impacts on loads). The analysis and inferences reached are reviewed in the following three sections:

[1] *Electricity Demand: Northeast and Northwest Divisions of Florida Public Utilities Company.*

II. *FPU Northeast:*

II.A Comparison of Weather Differences between the regions of FPU Northeast and FPL

III. *FPU Northwest:*

III.A Differences between FPU Northwest and Gulf Power in the Regional Markets Served

III.B Analysis of Peak Loads and Weather, FPU Northwest

III.C Analysis of System Load Factor and Residential Energy Shares, FPU Northwest

IV. *Summary of Findings*

The report includes a technical appendix titled *Extended Analysis of Load Factor and Energy Shares* (Appendix 1).

Report Section II (*FPU Northeast*) and Section III (*FPU Northwest*) explore regional differences, and the implications of using proxy load research data across regions when the characteristics of the underlying economies and weather are not closely matched. In the case of FPU Northeast and FPL, Section II reviews weather differences and reaches the conclusion that the use of FPL proxy load research to allocate demand charges is likely to contain significant estimation error, for FPU Northeast. Section III presents a descriptive analysis highlighting differences between the markets of FPU Northwest and of Gulf, as well as presents two types of more rigorous statistical analyses—one studying the relationship between load factor and residential shares, and the other examining the relationship between peak loads and weather, both using data for FPU Northwest. The narrative highlights how regional differences likely translate into estimation error and bias in the relationship between class peak demand and energy when the Gulf load research is used as a proxy for FPU Northwest, despite similarities in weather. Specifically, load factors and estimated peak demand shares for residential customers of FPU Northwest, as derived from Gulf Power's load research, will likely result in an overstatement of the residential peak demand responsibility.

II. FPU NORTHEAST

II.A Comparison of Weather Differences Between the Regions of FPU Northeast and FPL

As alluded to at the outset, the suitability of load research data of neighboring utilities for FPU is contingent upon the similarity: Is weather experience as well as economic and demographic characteristics of the regions of neighboring utilities well matched to FPU's Northeast and Northwest Divisions? Weather of Northwest Florida is generally similar across the peninsula; for this reason we have so far focused on the degree to which the regional economy, household characteristics, and housing stock of Northwest Florida generally served by Gulf Power matches Calhoun, Jackson, and Liberty counties, as served by FPU's Northwest Division.

The question of whether FPL's broad-ranging service territory is well matched to FPU Northeast is mainly a matter of the similarity—or differences—of weather. Weather patterns determine loads; it is predominantly the day-by-day and seasonal differences in weather that drive variation among week day hourly loads as well as among weekend loads also.

Weather differences (or similarities) between FPU Northeast and FPL are reflected in heating and cooling degree day metrics, hereafter referred to as HDDs and CDDs respectively. For the immediate study, daily HDDs and CDDs for the service territories of FPL and FPU Northeast are gathered over the 1990–2010 timeframe. FPL provides retail electricity services to much of Florida. Because weather varies considerably across FPL's region, daily HDDs and CDDs have been gathered for the weather zones relevant to FPL, and then weighted by the county populations for the counties within each zone.[2] Zonal weights are shown in Table 1.

[2] This approach incorporates a degree of estimation error. First, various areas of the counties served by FPL are of course also served by other retail electricity serve providers. Second, the underlying weather sensitive loads within the zones will not exactly match population. Third, the population of some counties is likely to have significant seasonal dimension.

Table 1: Determination of Zonal Weights Used for Weather Metrics

ZONE	POPULATION OF WEATHER ZONES SERVED BY FPL	WEIGHT
1	0	0.0%
2	857,022	9.2%
3	1,822,317	19.6%
4	1,075,361	11.6%
5	2,927,349	31.5%
6	2,603,587	28.0%
7	0	0.0%
TOTAL	**9,285,636**	**100.0%**

The HDDs for the various zones, as well as the weighted average for the FPL service territory or region, are shown in Table 2.

Table 2: HDDs for Weather Zones
Served by FPU Northeast (F B and JAX), FPL and PEN[3]

ZONE	J	F	M	A	M	J	J	A	S	O	N	D	TOTAL
Zone 2	380	270	153	43	2	0	0	0	0	31	141	314	**1333**
Zone 3	271	195	99	22	0	0	0	0	0	8	74	207	**876**
Zone 4	202	146	72	13	0	0	0	0	0	3	47	148	**631**
Zone 5	130	96	36	6	0	0	0	0	0	0	20	86	**374**
Zone 6	90	66	24	2	0	0	0	0	0	0	9	52	**243**
FPL Avg.	178	129	60	12	0.2	0	0	0	0	5	42	128	**554**
JAX	380	257	156	55	5	0	0	0	0	28	145	323	**1350**
F B	358	252	145	40	3	0	0	0	0.	16	109	292	**1215**
PEN	429	297	176	51	2	0	0	0	1	37	174	370	**1537**
Miami	53	26	11	1	0	0	0	0	0	0	3	34	**128**

One cannot avoid being struck by the magnitude of the weather differences between FPL's region and Fernandina Beach and the Jacksonville area, which proxies for FPU Northeast. Fernandina Beach has nearly twofold higher HDDs than the FPL region. For Miami, situated in zone 6 and one of FPL's very largest areas, HDDs are of virtually no

[3] *JAX* refers to Jacksonville. *F B* refers to Fernandina Beach, which is a better weather station for FPU Northeast, but Jacksonville is also used here because hourly data have been used for some comparisons and adequate hourly data are not available for Fernandina Beach. *PEN* refers to Pensacola Regional Airport, the primary station for Pensacola, and represents the service territory for Gulf Power.

consequence.[4] In contrast, Pensacola is very similar to Jacksonville and Fernandina Beach.

A similar though less dramatic conclusion is reached when CDDs, which proxy for the demand for cooling, are compared between FPU Northeast and FPL regions. These are shown in Table 3. Here again, the correspondence of Fernandina Beach is much closer to Pensacola than the FPL aggregate.

Table 3: CDDs for Weather Zones
Served by FPU Northeast (F B and JAX), FPL and PEN

ZONE	J	F	M	A	M	J	J	A	S	O	N	D	TOTAL
Zone 2	12	15	47	117	302	443	512	503	393	191	57	17	**2607**
Zone 3	24	33	76	155	330	460	523	518	441	277	104	42	**2983**
Zone 4	42	56	112	186	358	476	531	537	466	315	144	68	**3291**
Zone 5	64	84	131	205	354	463	522	534	480	366	186	103	**3490**
Zone 6	93	111	175	250	393	484	538	550	501	409	233	136	**3870**
FPL Avg.	57	72	123	197	356	468	527	533	468	338	166	88	**3392**
JAX	11	18	54	113	288	449	536	521	396	197	61	21	**2664**
F B	10	14	49	121	313	462	546	530	426	236	76	21	**2803**
PEN	6	8	33	101	300	465	533	521	403	180	46	13	**2609**
Miami	151	171	247	324	463	532	592	595	537	460	300	203	**4575**

Above, we observe higher CDDs for the FPL region than for FPU Northeast, with an overall annual difference of about 28%. However, Miami is once again in the tail of the distribution, with CDDs approximately one third higher than the average CDDs for the FPL region. And while the differences in CDDs for FPU Northeast and FPL are small during the summer months, winter CDDs for FPU Northeast typically range from 20% to 40% of the recorded levels for the FPL region. Again, the match between FPU Northeast and Pensacola, and hence Gulf Power, is much better than the match with FPL.

[4] Miami area HDDs can on occasion be highly concentrated over, say, 2–3 days, thus giving rise to sharply higher peak loads but very little heating kWh, resulting in a very low load factor.

It is useful to gauge the temporal variation in the HDDs and CDDs for the two regions. The maximum (peak day) and average HDDs, and the corresponding ratio average-to-maximum are presented in Table 4. Average heating load for FPU Northeast, as proxied by the Jacksonville weather (JAX), is significantly above that of the FPL region, as proxied by Miami and Orlando (ORL).[5] As a consequence, the difference of the average/peak ratio is significantly lower for the FPL region than for the area served by FPU Northeast.

Table 4: Maximum and Average Daily HDDs and the Average/Max Ratio (Heating Seasons 1990/91 to 2010/11)

	Peak Day HDDs			Average HDDs per Day			Average, % of Peak		
Year	JAX	MIAMI	ORL	JAX	MIAMI	ORL	JAX	MIAMI	ORL
1990	28.5	16.0	24.0	4.3	0.2	2.5	15.0%	1.3%	10.3%
1991	26.5	10.0	17.5	6.4	0.3	2.2	24.2%	2.9%	12.5%
1992	27.0	12.0	22.5	6.0	0.2	2.4	22.1%	1.9%	10.8%
1993	32.5	9.0	17.0	6.2	0.4	2.3	19.2%	4.3%	13.8%
1994	29.5	13.0	21.5	5.3	0.5	3.9	17.8%	4.1%	18.2%
1995	34.5	16.5	26.5	7.8	1.3	1.9	22.6%	7.7%	7.0%
1996	32.5	18.5	25.0	5.4	0.4	3.0	16.5%	2.3%	11.9%
1997	25.0	8.0	18.0	6.1	0.6	1.7	24.5%	8.0%	9.5%
1998	33.5	14.0	24.5	4.7	0.3	2.2	14.0%	2.4%	8.9%
1999	30.0	11.0	22.0	5.8	0.4	3.4	19.2%	3.6%	15.4%
2000	33.5	16.0	28.0	7.5	0.9	2.2	22.5%	5.6%	7.7%
2001	27.0	16.5	24.5	4.9	0.4	3.5	18.1%	2.5%	14.2%
2002	34.5	18.0	30.0	7.2	0.7	2.7	20.8%	3.7%	9.0%
2003	28.0	11.0	19.5	6.9	0.6	2.4	24.7%	5.1%	12.6%
2004	28.5	10.0	20.0	6.2	0.6	2.4	21.9%	6.2%	11.8%
2005	26.5	13.5	20.5	5.9	0.5	2.2	22.2%	4.0%	10.6%
2006	26.0	11.5	18.0	5.5	0.4	1.7	21.3%	3.2%	9.2%
2007	31.0	15.5	23.5	5.8	0.2	3.0	18.6%	1.3%	12.8%
2008	31.5	15.5	24.0	6.5	0.5	4.5	20.7%	3.3%	18.8%
2009	35.5	23.5	30.0	7.9	1.4	3.4	22.4%	6.0%	11.4%
2010	32.5	20.5	26.5	7.5	1.0	1.9	23.0%	5.0%	7.1%
Avg	30.2	14.3	23.0	6.18	0.57	2.63	20.5%	4.0%	11.6%
StDev	3.23	3.97	3.91	1.03	0.33	0.76	3.02%	1.91%	3.24%
Max	35.5	23.5	30.0	7.95	1.40	4.52	24.7%	8.0%	18.8%

[5] While Orlando is not served by FPL, it has, in aggregate the same level of heating and cooling as the FPL aggregate. Since hourly data were available for a prolonged period for Orlando and not for good alternatives, this location has been used for these graphical comparisons. The Orlando locale is not used in the summary tables above. Similarly, hourly data are not available for Fernandina Beach, so Jacksonville is used.

As revealed above in the right column set, the *average* of the Average/Peak HDD ratio for the FPU Northeast region varies little—20.5% average, 24.7% maximum, when compared to the CDDs for the FPL region—4.0% average, 8.0% maximum for Miami; and 11.6% average, 18.8% maximum for Orlando (see Table 5 for CDDs). In addition, FPU Northeast variation, as reflected in the temporal standard deviation (StDev), is low vis-à-vis Miami and Orlando, when compared to the average for the respective locations for the FPL regions (coefficient of variation).

Table 5: Maximum and Average Daily CDDs and the Average/Max Ratio, Cooling Seasons 1991 to 2011

	Peak Day HDDs			Average HDDs Per Day			Average, % Of Peak		
Year	JAX	MIAMI	ORL	JAX	MIAMI	ORL	JAX	MIAMI	ORL
1990	22.0	21.5	21.0	13.5	16.7	14.8	61%	78%	71%
1991	22.0	22.5	23.5	11.6	15.8	13.4	53%	70%	57%
1992	22.5	23.5	22.0	11.6	16.4	13.6	52%	70%	62%
1993	21.0	21.5	20.0	11.6	16.6	13.7	55%	77%	69%
1994	21.5	23.5	22.5	12.2	17.2	14.7	57%	73%	65%
1995	21.0	21.5	22.5	11.1	16.3	14.1	53%	76%	63%
1996	23.0	22.0	21.5	10.5	16.0	13.0	46%	73%	61%
1997	24.5	23.5	24.5	12.9	17.2	15.0	53%	73%	61%
1998	25.0	23.5	21.5	11.6	15.8	13.9	46%	67%	65%
1999	22.5	22.0	22.5	10.8	15.8	13.5	48%	72%	60%
2000	21.5	22.5	21.0	10.6	15.5	12.9	49%	69%	62%
2001	22.0	22.5	21.0	12.3	16.7	14.4	56%	74%	68%
2002	19.5	21.5	20.5	11.0	16.4	14.0	56%	77%	68%
2003	21.0	22.5	20.5	12.1	16.1	14.0	58%	71%	68%
2004	22.0	23.0	22.5	11.6	16.0	14.0	53%	70%	62%
2005	21.5	22.0	20.0	11.8	16.3	14.2	55%	74%	71%
2006	23.0	23.5	22.0	11.6	16.2	14.4	50%	69%	66%
2007	20.0	22.0	20.5	10.9	16.4	13.5	55%	75%	66%
2008	21.5	24.5	24.0	12.1	17.5	14.5	56%	72%	60%
2009	24.5	23.0	23.5	12.8	17.5	14.7	52%	76%	63%
2010	23.0	23.0	21.5	12.1	17.5	14.7	53%	76%	68%
Avg	22.1	22.6	21.8	11.7	16.5	14.1	53.1%	72.9%	64.5%
StDev	1.40	0.85	1.30	0.78	0.61	0.59	3.85%	3.04%	3.88%
Max	25.0	24.5	24.5	13.5	17.5	15.0	61.3%	77.9%	70.8%

The temporal pattern of the realized historical CDDs is of course quite different from HDDs for both the FPU Northeast and FPL regions. Three observations are reached.

First, for both regions, the average to maximum difference (average/peak ratio) for all years are remarkably reduced, when compared to HDDs. Second, the difference between the maximum and the peak ratio across years is dramatically lower for CDDs, than for HDDs. Third, the differences between the average/peak ratio for FPU Northeast and the FPL are modest, when compared to the differences in historical HDDs.
While the differences between the two regions are not as large for CDDs, the weather data for the two regions presented above nonetheless raise concerns about the match of FPL load research data to the FPU Northeast region. Specifically, the average to peak CDDs ratio for FPU Northeast is some 12%–20% lower, which implies that the difference between summer energy to peak demand, for residential customers in the Northeast would be higher, when compared to FPL. This implies that, other factors constant, FPL-based load research for residential customers would overstate the relationship between peak demand and average energy (load factor) for the Northeast during the summer months.

Differences are revealed in levels and in variation over time. A further perspective for the FPU Northeast (Jacksonville) and FPL (Miami, Orlando) regions can be gleaned from the following three graphs (Figures 1, 2, and 3), which present the frequency distributions (shown as percentiles) of maximum daily HDDs for selected months. As implied by the above weather tables, the distribution of weather for key months is considerably wider for FPU Northwest than for FPL, represented by the Miami and Orlando weather proxies.

Figure 1: Monthly Percentiles of Maximum HDDs for Jacksonville 1990–2011

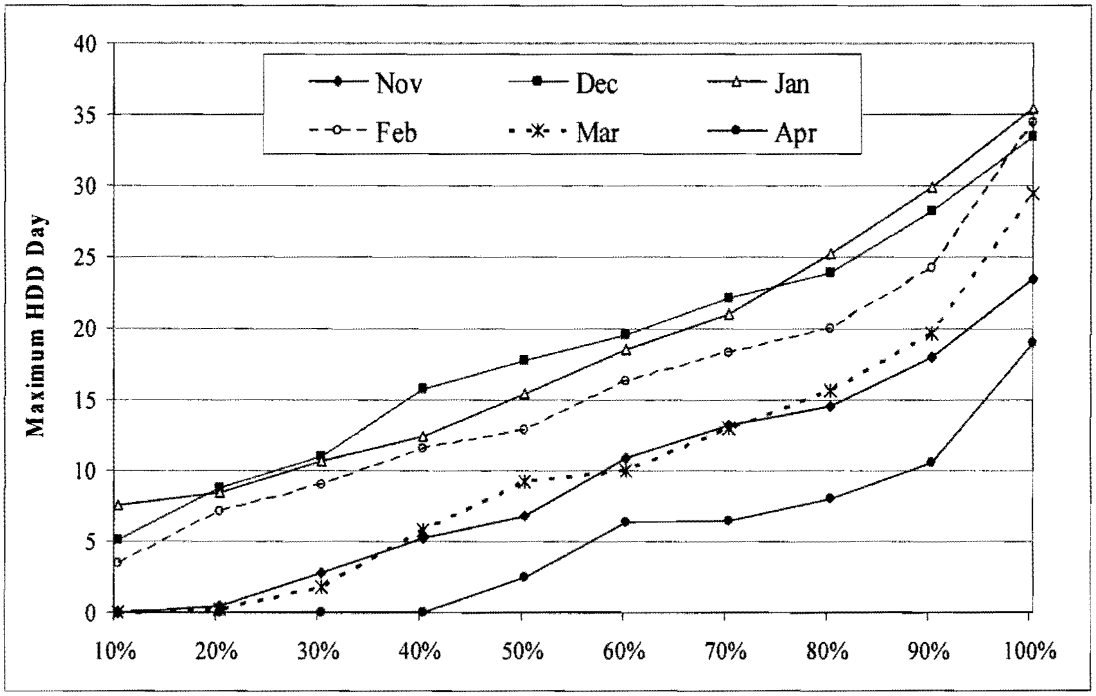


Figure 2: Monthly Percentiles of Maximum HDDs for Orlando 1990–2011

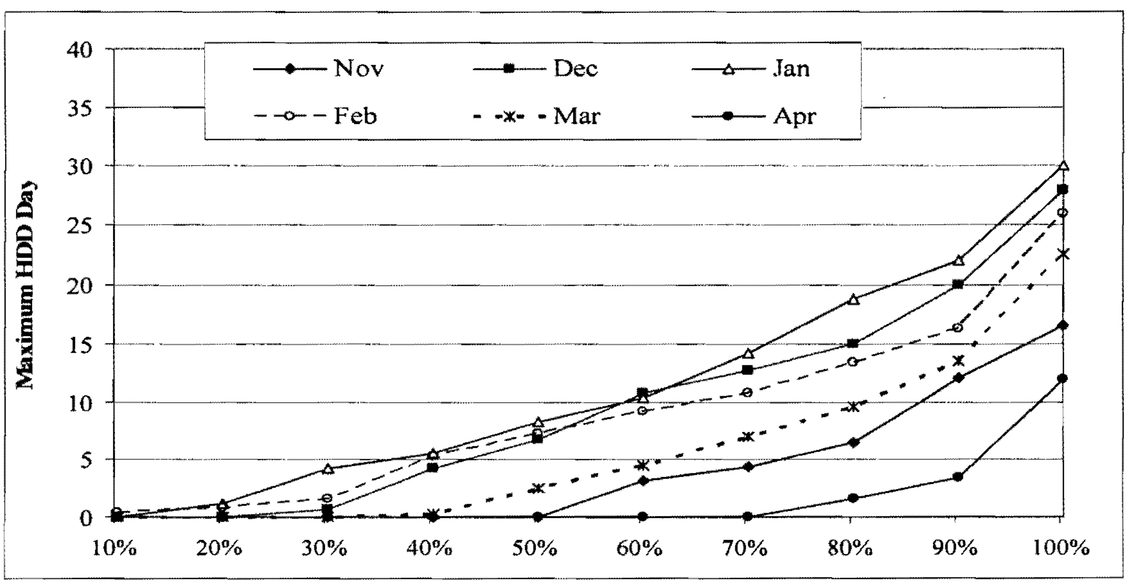
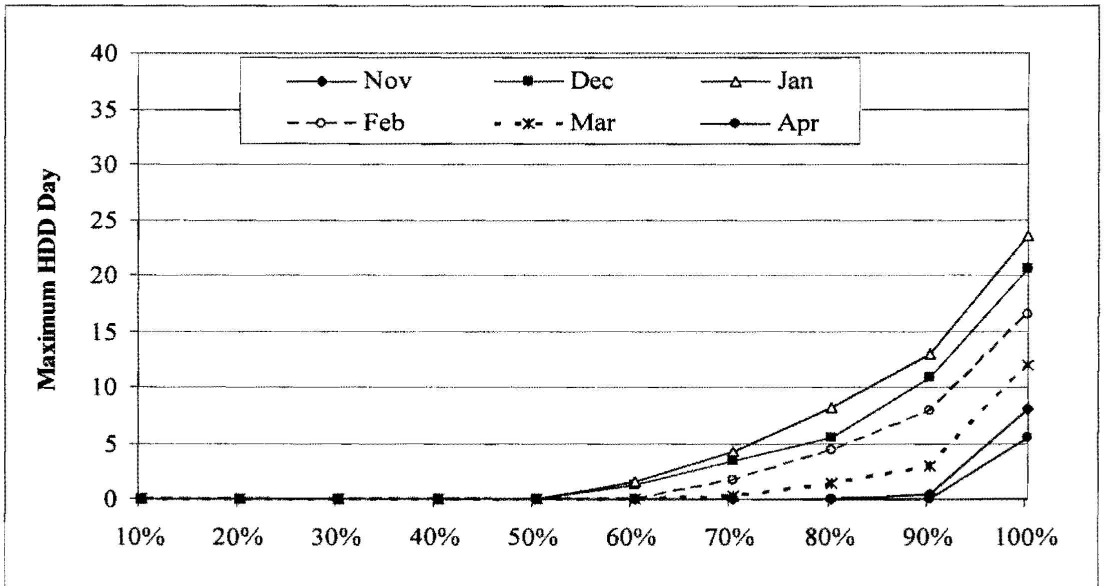


Figure 3: Monthly Percentiles of Maximum HDDs for Miami 1990–2011



For the core winter months, December–February, the Miami proxy (for FPL) demonstrates a remarkably lower distribution of HDDs than the Jacksonville proxy (for FPU Northeast). A similar story is observed for the Orlando proxy (for FPL), though the differences are less dramatic.

While differences in the underlying regional economies, demographic characteristics, and mix of business customers are surely present, the FPU Northeast FPL comparison focuses on weather differences between the two regions. Weather differences are telling, as weather drives space conditioning loads which to a substantial extent determine differences in average-to-peak loads of customer classes. In summary, measured in terms of level and also variation, the analysis finds large differences in winter and summer weather patterns between the two regions (FPU Northeast, FPL). The implications are that, at the very least, FPL load research results are unlikely to serve as a good proxy for the load experience of FPU Northeast.

Taken as a whole, we recommend that FPU Northeast consider utilizing Gulf Power Company's load research results as a starting point for demand charge allocation, in lieu of the load research results of FPL.

III. FPU NORTHWEST

III.A: Differences Between FPU Northwest and Gulf Power In the Regional Markets Served

Section III.A explores differences in demographic and economic characteristics between the customers of Gulf Power and the Northwest Division of FPU (Northwest Division, FPU Northwest), most notably in income levels, the proportion living below the poverty line, and in housing stock. The discussion begins by describing the weights used to determine the overall metrics for Gulf Power and FPU Northwest, and then presents the differences in the customer makeup of the regions served.

Weights for the Comparison Metrics, FPU Northwest and Gulf Power Company

We develop weights based on the number of residential customers of Gulf Power and FPU Northwest, in the respective counties served by each utility. In turn, the customer weights are used to aggregate the economic and demographic data for counties, where the end result is a composite view of Gulf's customer population. In the case of Gulf Power, retail services are provided within eight counties of Northwest Florida, four of which make up over 96% of the total population served.[6] Table 6 shows the distribution of Gulf Power customers across the several counties. The table reveals that the customer base for Gulf Power is strongly concentrated in Bay, Escambia, Okaloosa, and Santa Rosa Counties.

Table 6: Population and Percentage Weights, Counties Served by Gulf Power Company*

COUNTIES SERVED	NUMBER OF	PERCENT WEIGHT

[6] For Gulf Power, we develop weights based on the number of customers served in these top four counties. Since the remaining counties comprise less than 4% of the total population served, and have similar demographic characteristics, excluding them from the computation of weights does not qualitatively change the results.

	CUSTOMERS	
Bay	100,271	23.4
Escambia	174,177	40.7
Okaloosa	104,847	24.5
Santa Rosa	34,195	8.0
Holmes	2,314	0.5
Jackson	1,482	0.4
Walton	4,403	1.0
Washington	7,947	1.9
TOTAL	428,154	100

* Source: Web site of Gulf Power Company.

FPU's Northwest Division provides electricity service in Calhoun, Jackson, and Liberty counties, with customer weights developed accordingly. Table 7 shows the distribution of FPU Northwest customers for the three counties.

Table 7: Population and Percentage Weights, Counties Served by FPU Northwest

COUNTIES SERVED	NUMBER OF CUSTOMERS	PERCENT WEIGHT
Jackson	8,588	86.5
Calhoun	746	7.5
Liberty	593	6.0
TOTAL	9,927	100

* Source: Bureau of Economics and Business Research, University of Florida.

Data Source

The demographic, economic, and housing characteristics used for purposes of comparison between Gulf Power and FPU Northwest were obtained from the American

Community Survey (ACS, Survey), which is a critical element in the Census Bureau's decennial census program. The ACS is a nationwide survey which collects information on age, income characteristics, education, employment, and housing characteristics. ACS data are available at the county level. We used the Survey's 5-year estimates, which represent the characteristics of the population and housing for the January 2006–December 2010 period, to draw the comparisons.[7] From ACS data bases, we culled information for the four major counties served by Gulf Power shown in Table 6, and the three counties served by FPU Northwest, shown in Table 7.

Comparisons of Demographic Characteristics

For the two regions, the main demographic characteristics include age distribution of customers, residential household type, and the level of employment levels by educational categories.

In Table 8, significant differences between the two regions are shown. In general, it appears that residential customers and the underlying population of FPU Northwest tend to be somewhat older than those served by Gulf Power. Specifically, the median age of residential consumers is higher by approximately 2 years in the FPU Northwest region than in the region served by Gulf. We observe a smaller share of comparatively young individuals in FPU Northwest region than in Gulf Power's region. Specifically, the share of individuals aged 19–24 years in the FPU Northwest area is almost 4 percentage points lower than in regions served by Gulf Power. Correspondingly, the proportion of older individuals aged 25 and above is higher in the Northwest Division service territory than for the area served by Gulf Power, again by almost 4 percentage points. It is worth noting that the proportion of elderly in the FPU Northwest region (aged 65 years and more) is considerably higher than in the Gulf Power territories. Additionally, the proportion of households with individuals aged 65 and above *living alone* is almost 2.3

[7] Although 1-year and 3-year period estimates are also available from the ACS, the 5-year estimates are generally considered to be the most reliable and more appropriate when studying smaller geographies such as counties.

percentage points higher in counties of the FPU Northwest area than in the Gulf Power counties.

Table 8: Age Distribution of Population and Household Type

AGE GROUP	FPU NORTHWEST	GULF POWER COMPANY
Median Age	39.9	37.8%
19 years and less	23.1%	25.8%
20–24 years	6.9%	7.8%
25–44 years	27.3%	25.8%
45–64 years	27.6%	26.8%
65 years and more	15.0%	13.7%
HOUSEHOLD TYPE	**FPU NORTHWEST**	**GULF POWER COMPANY**
Aged 65 and living alone	11.8%	9.5%

Table 9 shows the educational attainment levels of individuals in both regions across two population subgroups—individuals aged 18–24 years, and individuals aged 25 years and older. We incorporate education characteristics in the review, as it is strongly correlated with household income, and thus housing stock and electricity consumption. For these two age groups, the proportion of customers with lower levels of education is substantially larger for FPU Northwest's territory than for the Gulf Power region. For the over 25 years and older age group, the proportion of the population with comparatively high levels of schooling is nearly twice the corresponding proportion for FPU Northwest's territory.

Table 9: Educational Attainment

POPULATION AGED 18–24 YEARS	FPU NORTHWEST	GULF POWER COMPANY
Less than High School Graduate	35.7%	15.4%
Bachelor's Degree or Higher	4%	5.6%
POPULATION AGED 25 YEARS AND OLDER	**FPU NORTHWEST**	**GULF POWER COMPANY**
Less than High School Graduate	23%	12.2%
Bachelor's Degree or Higher	12.7%	23.6%

Table 10 and Figure 4 depict a more granular view of the statistical distribution of educational attainment. Figure 4 plots the ratio of the population shares regarding education attainment, for FPU Northwest and Gulf Power. Significant differences across the educational distributions are observed for customers of the two utilities. As shown in Figure 4, the population/residential customer share with educational attainment less than 9th grade in the FPU Northwest region is 2.5 times higher than for Gulf Power, which translates into an approximately six percentage point difference. For the highest education category, the population/residential customer share for the FPU Northwest region is approximately one half that of the population of the Gulf Power region. Similarly for the Graduate or Professional Degree category, the population share for the FPU Northwest region is one half the level for the population of the county region served by Gulf. The sharp downward slope of the graph suggests that the concentration of highly educated individuals is significantly greater in the Gulf Power service region, as compared to the FPU Northwest service region. We conjecture that, to a substantial extent, the observed differences reflect, for Gulf Power, a larger share of the population served resides in urban areas plus close proximity to the Gulf Coast where incomes are likely to be comparatively high.

The data in Table 11 reveal significant differences in the characteristics of the residential housing stock for the two areas. The most striking difference is the share of mobile homes, which in the FPU Northwest counties is about three times more than for the Gulf Power counties. As far as vintage is concerned, homes in the FPU Northwest region are older than in the Gulf Power areas, as revealed by the significantly larger share of homes built after 1990 in the Gulf Power territory vis-a-vis FPU Northwest.

Table 11: Housing Characteristics

HOME FEATURE	FPU NORTHWEST	GULF POWER COMPANY
Mobile Homes	28.9%	9.3%
Homes built after 1990	27.7%	36%
Renter occupied homes	23.0%	32.1%

Comparisons of Economic Characteristics

The consideration of economic well being takes account of three income metrics: distribution of household income, incidence of poverty, and employment.

As Table 12 indicates, we find significant differences in the level of income across residential customers of the two utilities. For three income indicators including per capita income, median income of the family, and median income of households, residential customers of FPU Northwest have considerably lower incomes than Gulf Power residential customers. Specifically, per capita income, median income of the family, and median income of the household is 32.8%, 15.6%, and 21.4% higher, respectively, for households served by Gulf Power than those served by FPU Northwest.

Table 12: Per Capita and Household Income

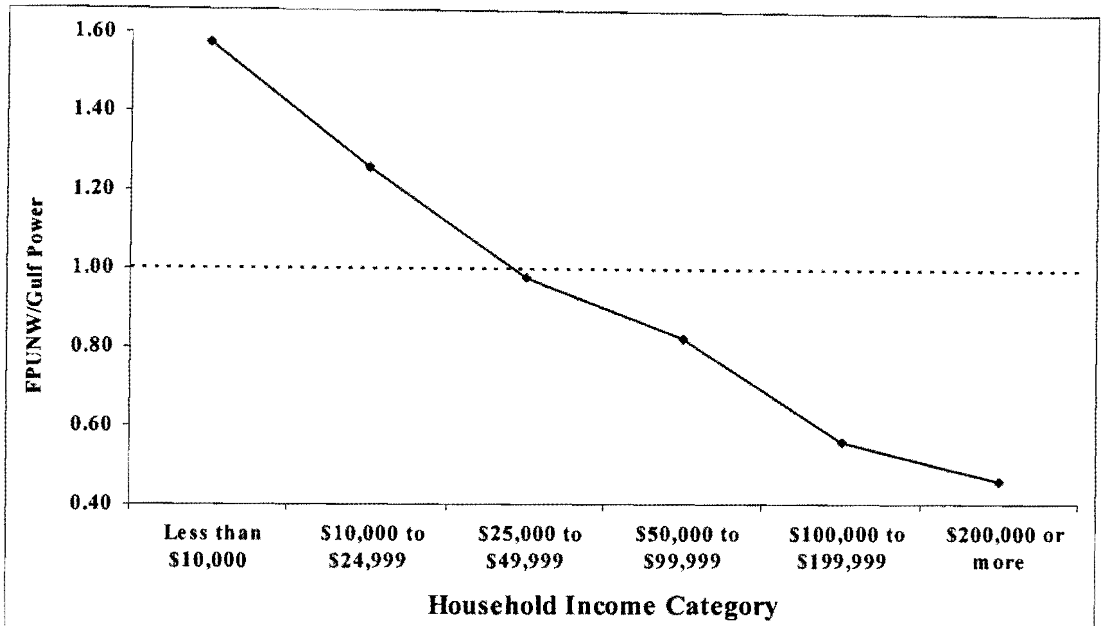
INCOME METRICS	FPU NORTHWEST	GULF POWER COMPANY
Per Capita Income	$17,010	$25,315
Median Income Family	$48,778	$57,816
Median Income Household	$37,915	$48,252

Table 13 and Figure 5 show the comparisons across the household income distribution for FPU Northwest and Gulf Power. Figure 5 plots the ratio of the shares for FPU Northwest and Gulf Power. We find that there exist fairly wide differences in the income levels of households for the two regions. For example, according to Figure 5, there are approximately 50% more FPU Northwest households with incomes less than $10,000 per year. Conversely, for households earning above $100,000 per annum, the ratio of FPU Northwest to Gulf Power is almost one half (0.54).

Table 13: Household Income Distribution

INCOME CATEGORY	FPU NORTHWEST	GULF POWER COMPANY
Less than $10,000	11.0%	7.0%
$10,000–$24,999	21.3%	16.9%
$25,000–$49,999	27.2%	27.8%
$50,000–$99,999	26.8%	32.5%
$100,000–$199,999	7.3%	13.1%
$200,000 or more	1.2%	2.7%

Figure 5: Household Income Distribution (Ratio of Shares)



For the two regions, there also exist fairly wide differences in the proportion of customers living below the poverty line. As Table 14 indicates, across the defined measures of poverty, we find a significantly larger percentage of low income households, and thus customers, for FPU Northwest than for Gulf Power counties. In fact, the share of individuals aged 65 and above living below the poverty line in FPU's Northwest Division is almost twice the corresponding share for the Gulf Power region.

Table 14: Incidence of Poverty

Population Below The Poverty Line	FPU Northwest	Gulf Power Company
Families	11.5%	10.0%
Population	19.5%	13.5%
Below 18 years of age	16.8%	16.7%
Above 65 years of age	16.3%	8.6%

The final dimension of economic well being, as examined, is the level of employment across the two regions. The overall share of employment in the FPU Northwest region is

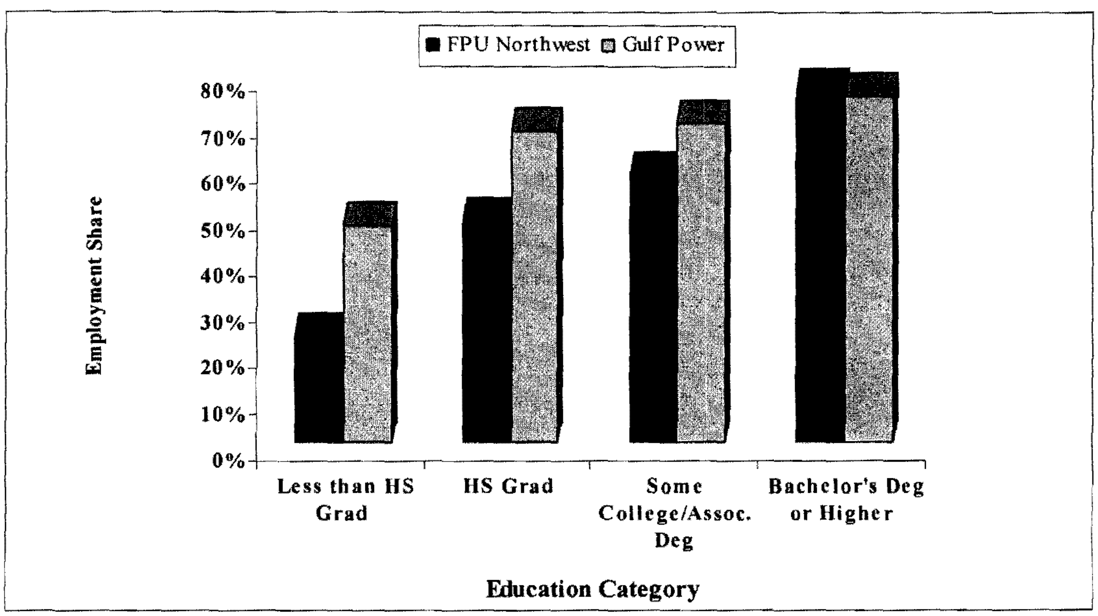
49.6%, and the corresponding number for the Gulf Power region is significantly higher at 67.9%. Figure 6 shows the distribution of employment across education categories. We observe considerable differences across most education groups, with a noticeably higher share of residential customers being employed in the Gulf Power service area.

In summary, Gulf Power residential customers appear to have rather significantly higher levels of well being than the residential customer base of FPU Northwest.

Load Implications of Regional Differences, FPU Northwest and Gulf Power

The differences in the residential markets served, as highlighted above, especially housing characteristics, economic indicators, and incidence of poverty, suggest that the underlying load shapes and the residential peak loads for the Northwest Division may be differentiated from those of Gulf Power in important ways.

Figure 6: Employment Share Across Education Categories



Source of Systematic Bias in Estimated Residential Peak Energy Usage Northwest Division: The analysis above demonstrates a much higher share of mobile homes within the housing stock served by FPU Northwest than for Gulf Power. This result is fully in keeping with the larger share of comparatively low income households. The prevalence of window air conditioner (A/C) units is likely to be much higher among FPU Northwest customers than among residential customers of Gulf Power. The implication is a truncated peak load-to-average energy ratio for FPU Northwest customers, as mobile homes predominantly use window air conditioning. There are several reasons for this result:

a) Window A/C units typically provide only compromised capability to manage exceptional temperatures, whereas central A/C units tend to be installed with capacity that approximates or exceeds expected maximum requirements. Thus window A/C units typically hit constraints on output levels well before the peak hours on the hottest days. Conversely, central A/C of stationary homes is often oversized; the spare capacity implies that usage continues to climb with temperatures, rather than plateauing. Hence, loads on peak temperature days for window units are typically not much higher than the peak usage on cooler days.

b) With central A/C, peak days lead to substantially higher loads when the A/C is 'over-designed', especially since unit efficiency declines as the temperature increases.

c) Households with central A/C units tend to be programmed to increase the cooling levels a bit before people return home, leading to more cooling demand during the peak hours, and less in the periods immediately before and after the peak hours.

d) Single individual households (living alone and "at home" during mid-day hours) will tend to have reduced differences between average and peak hour loads during peak temperature days.[8]

Loads are concave with respect to temperature at the top end of the load-temperature function for virtually all electric utilities. This change in the load-temperature relationship as temperatures rise is driven by air conditioners reaching maximum duty cycles as temperatures increase. Individual customer data reveal this result: progressively more households hit capacity constraints as temperatures rise; households with window A/C units are the most limited. For FPU Northwest the effect is somewhat pronounced, we believe, as retail usage at the daily maximum appears to be increasingly constrained

[8] This is particularly relevant when the incidence of window A/C units is positively correlated with single individual households.

during peak days. This can be seen in a plot of loads against temperature, which demonstrates a concave function toward the top end. The statistical analysis contained below in Section III.B confirms this declining impact of temperature on peak loads.

Energy Behavior and Peak Usage: The comparatively lower incomes of the FPU Northwest residential customers suggest an older and less updated housing stock, as compared to their Gulf Power counterparts. As noted earlier, the share of homes built after 1990 in the region served by Gulf Power dominates that of the FPU Northwest territory. Generally speaking, older homes have somewhat more rooms, and are less energy efficient, and require a greater amount of electricity to cool than a newer home of the same size, though they are likely to show less variation in space heating load with respect to differences in temperatures. The result is to reduce the differences between the average and peak day loads, for air conditioning.[9] Inferences are as follows:

a) According to the Residential Energy Consumption Survey, homes built since 1990 are on average 27% larger than homes built in earlier decades. Since the share of homes built before 1990 is significantly higher in the FPU Northwest region, this would then imply, in general, homes may be somewhat larger among Gulf Power consumers. This would correspond to the finding that Gulf Power customers have higher incomes. Also, larger income households commonly have a greater number of occupants. All these factors would lead to differences in the energy behavior and may also impact the duration (and hence usage) of peak hours.[10]

b) Higher income households will typically have higher concentrations of electricity-consuming appliances and devices, and may use them more extensively than lower income households. Higher income may also be reflected in the quality of the household appliance stock. The implication is that the profile of residential base loads for FPU Northwest may be somewhat

[9] This effect could be included in the systematic effects. However, since the main effects drive several of the items listed in that section, they have been categorized here to be 'conservative'.

[10] According to results from the Energy Information Administration's 2009 Residential Energy Consumption Survey (RECS), the stock of homes built in the 1970s and 1980s averages less than 1,800 square feet. That average increases to 2,200 square feet for homes built in the 1990s and to 2,465 square feet for homes built in the 2000s. While the average floor area has been increasing, so has the ceiling height of many new homes. RECS data show that just 17% of homes built in the 1970s have higher than the traditional eight-foot ceilings, while that number increases to 52% in homes built in the 2000s.

differentiated from the profile of base loads of the residential class of Gulf Power.

c) Different electricity consumption patterns between the two regions can come about from differences in home daytime occupancy. This inference is reflected within the above comparisons in three ways. First, the FPU Northwest region is not only comprised of a significantly higher percentage of older and (perhaps) retired individuals, but also of a higher proportion of individuals aged 65 and above who are living alone. Older householders may have comparatively lower evening energy consumption patterns compared to their younger counterparts. Additionally, higher daytime occupancy in the FPU Northwest area, as inferred, may be related to, and caused by, observed lower employment shares as well as lower incomes in the region, both overall and across education groups. Unemployed individuals typically have lower incomes, which in turn affects the share of daytime energy consumption.

d) The larger proportion of elderly in the counties served by FPU Northwest has other identifiable implications for electricity usage. First, reduced expenses (e.g., those related to the upbringing of children) may enable elderly households to purchase additional appliances and energy using devices, if desired. However, life cycle and convenience choices may lower the frequency of upgrading and extending appliance stocks. Second, older people may choose to live in smaller residences. Third, smaller family sizes within their homes (e.g., elderly living alone) would imply, notwithstanding space conditioning, that fewer demands are being placed on the operation of appliances which in turn would directly influence electricity consumption.

III.B: Analysis of Peak Loads and Weather, FPU Northwest

As noted above in Section III.A, for FPU Northwest, a plot of loads against temperature generally demonstrates a concave function toward the top end. In this sub-section, we review the statistical analysis that demonstrates the declining impact of temperature on peak loads. The analysis consists of a regression study of the daily maximum load on an *index of daily temperatures* plus a set of other variables. Empirical results provide clear evidence of concavity in the relationship between peak loads and temperature toward the top of the load-weather function. Essentially, the marginal effect of temperature on load is higher at temperatures that are less than the highest temperatures. The analysis conforms with the economic and demographic profiles presented above: comparatively lower income levels of the residential customers of FPU Northwest translate into higher shares of mobile homes and window air conditioners. Moreover, stationary homes within the FPU Northwest area are likely to have a higher prevalence of window A/C units in view of the older housing stock.

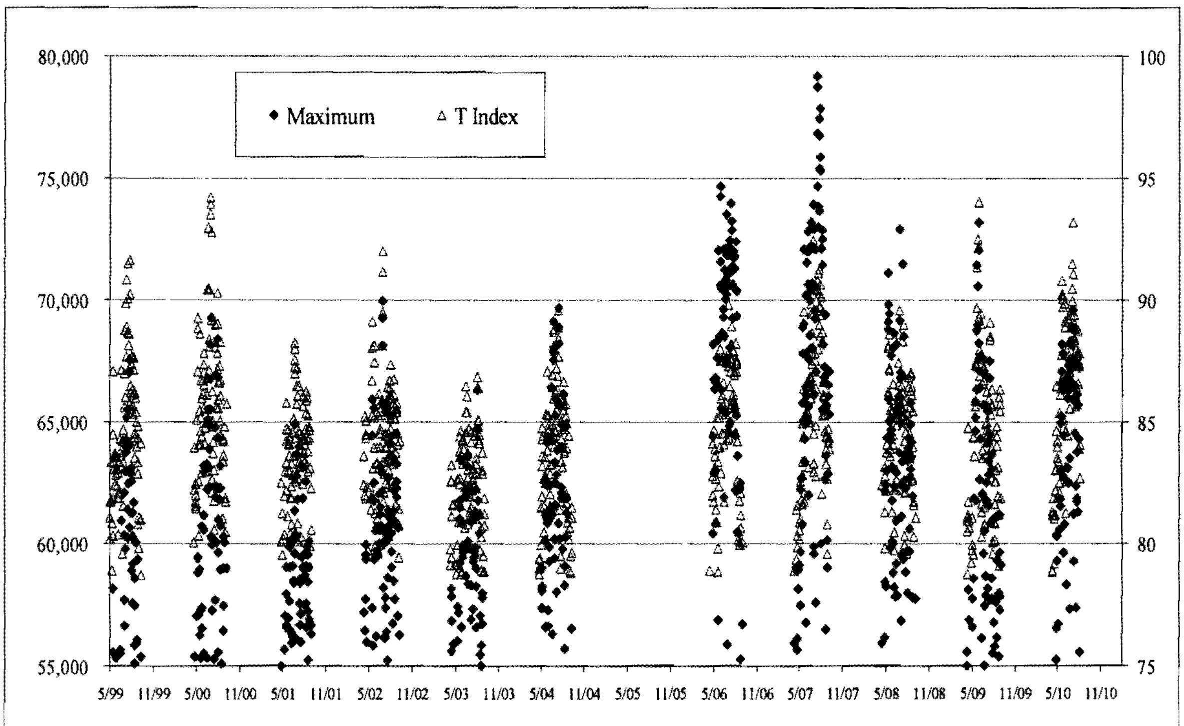
In brief, FPU Northwest will likely have a much higher share of window A/C than Gulf Power. Since window A/C units reach the 100% duty cycle prior to reaching peak temperatures, peak day load shapes during the summer have a reduced load/temperature gradient toward the top of the load-temperature function. Because of the importance of the residential class, load research results drawn from Gulf Power may not be fully applicable to FPU Northwest. Specifically, it is likely that the use of Gulf Power load research for FPU Northwest will implicitly overstate the residential contribution to peak demands during summer months, which in turn determines the share of wholesale demand charges paid by the residential customers. What follows is a detailed account of the regression methodology and corresponding results.

The various aspects of the study draw on weather and usage data for 1999–2010 (except for 2005). Our review of these data confirms the usual notions of the relationships between peak demands and weather. In addition, the data review also brought out several indications that the electricity demand-weather relationship, for FPU Northwest, is perhaps more nuanced than basic constructs would suggest. Figure 7 plots daily peak loads and an index of the day's weather,[11] revealing that by far the highest loads (2007, 2006) are not accompanied by the hottest temperature indexes. The very high

[11] The temperature index consists of lagged weights on both peak temperatures and minimum temperatures covering nearby days, with a weight of 0.60 applied to the temperature of the current day, a weight of 0.30 applied to the prior day, and a weight of up to 0.10 used for the second and third prior days' weather. One reason for this approach is that the day's minimum could occur near midnight after the peak afternoon usage; thus, the prior day's minimum is more relevant. In addition, the minimum temperature is a proxy for the dew point (the temperature when the air is saturated, which may yield near 100% relative humidity). The dew point is important for two reasons. First, moist air takes more energy to cool, and second, people feel more uncomfortable at a given temperature with a comparatively high dew point. Finally, there has been a substantial anecdotal and empirical evidence of persistence: as the building stock heats up, air conditioning demands are highest after a succession of days of very hot weather rather than one day with a very high peak temperature. Hence, the maximum temperature gets two-thirds of the weight within the day.

temperatures of 1999 and 2000 have loads 15% lower than 2007 and 2006. In general, this observation is not surprising when load is growing rapidly or at least systematically over time, as "new loads" tend to be associated with increased energy efficiency. Moreover, the most recent years also have high temperatures without particularly high loads.

Figure 7: Hot Summer Days, Max kW and Temperate Index



The analysis of loads and temperature is based on regression analysis of daily maximum load on the daily temperature index, as constructed, plus a set of binary variables. Binaries include three sets of variables:

- Hour of the maximum of the day, $Hour_{h,d}$, h = 14, 15, and 16 (with all the remaining hours grouped together as the baseline);
- Year y, $Year_{y,d}$, y = 1999-2010 (excluding 2005); and,
- Beginning and End of Week D_i, i = Monday, Friday; beginning and end of week days are identified because these two days (especially Fridays) have comparatively lower loads, other factors held constant.

Thus, the load-temperature model is:

$$kW_d^{max} = \beta o + \beta_{Temp} TempIndex_d + \sum_h \beta_h Hour_{h,d} + \sum_y \beta_y Year_{y,d} + \sum_i \beta_i D_{i,d} + \varepsilon_d$$

The dataset used to estimate the load temperature model is sorted in two ways: by the Temperature Index; by maximum usage, kW_d^{max}. For each sort type, regressions were run on the top 100 load days, the top load 200 days, …, and the top 1100 load days.[12]

The following tables present a summary of a subset of the load-temperature regression results. From Table 15, we can observe that given the diversity of days and the range of years, the load-temperature models fit reasonably well, although the difference between sorting by the Temperature Index and by Maximum kW are fairly large until a substantial fraction (about 400) of the top days are included.

Table 15
Goodness of Fit for Models of Top Days, Shown for Alternative Sort Criteria

	R-SQUARED STATISTICS	
GROUP	MAXIMUM KW	TEMPERATURE
Top 100	59.5%	77.4%
Top 200	68.0%	79.2%
Top 300	69.8%	79.4%
Top 400	74.8%	78.6%
Top 500	75.5%	77.8%
Top 600	76.9%	78.5%
Top 700	77.7%	79.4%
Top 800	79.2%	80.1%
Top 900	81.0%	79.9%
Top 1000	82.2%	80.7%
Top 1100	83.5%	83.5%

Tables 16 and 17 provide the load-temperature regression results. Rather than display each of the category variables, the regression coefficients and *t*-statistics are averaged in

[12] There are a total of 1149 days. However, the last 49 days are more likely to have unusual events, including partial outages, severe storms, etc., and were thus excluded.

order to provide a descriptive summary of the regression results.[13] Most of the estimated coefficients match expectations, with Friday afternoons often involving, we infer, workers leaving early, production plants ramping down, and commercial buildings cutting back on air conditioning thus allowing inside temperatures to rise. The grouping by year generally matches the image provided in the above figure. Finally, the estimated coefficients have good diagnostic statistics, as shown by the *t*-statistics presented in the lower portion of the tables. As expected, the temperature index variable is highly significant and climbs steadily with increased observations.

Table 16
Beta Coefficients for Regressions *Sorted by Temperature Index*
(Coefficients shown in top table; Accompanying *t*-statistics in bottom table)

		DAY	HOURS	YEAR GROUPS				
GROUP	TEMP INDEX	FRIDAY	14–16	1999–2001	2002–2004	2006–2007	2008	2009–2010
Top 100	1070	−1362	5213	149	3344	9455	7898	3287
Top 200	980	−1731	3494	−244	3406	9249	5737	3345
Top 300	1224	−1821	3602	152	3271	9263	5418	2618
Top 400	1294	−1702	3578	167	3358	9400	5105	2473
Top 500	1356	−1718	3405	258	3021	9531	5383	2566
Top 600	1451	−1474	3192	597	3799	9959	5828	2930
Top 700	1476	−1560	3038	802	4254	10218	6243	3119
Top 800	1522	−1601	3207	826	3875	10140	6019	2913
Top 900	1573	−1446	3224	972	3647	10139	6024	2938
Top 1000	1642	−1639	2968	1307	3995	10310	6243	3296
Top 1100	1615	−1654	2795	1229	3935	10167	6271	3206

[13] In these two tables, Monday has been omitted; the coefficient is typically a quarter that for Friday. Additionally, the hour variables have been averaged together as have some of the years.

		Day	Hours	Year Groups				
Group	Temp Index	Friday	14–16	1999–2001	2002–2004	2006–2007	2008	2009–2010
Top 100	5.6	–2.21	5.2	0.0	2.3	8.1	5.2	3.3
Top 200	9.4	–4.57	6.0	–0.3	4.0	14.5	7.1	5.3
Top 300	15.1	–5.53	7.3	0.1	4.0	16.2	8.6	4.5
Top 400	18.6	–5.76	8.8	0.1	4.9	17.9	9.4	4.6
Top 500	21.7	–6.11	8.9	0.4	5.0	18.3	10.1	4.9
Top 600	25.9	–5.51	9.2	1.1	7.0	20.3	11.7	5.9
Top 700	30.0	–6.15	9.5	1.7	8.8	22.5	13.7	6.7
Top 800	34.9	–6.46	10.5	1.8	8.4	22.6	13.6	6.3
Top 900	39.6	–5.81	10.6	2.1	7.9	22.0	13.2	6.4
Top 1000	47.0	–6.61	9.9	2.8	8.8	22.6	13.7	7.2
Top 1100	57.5	–6.85	9.8	2.8	8.9	23.0	14.3	7.1

Table 17
Coefficients for Regressions *Sorted by Max kW*
(Coefficients shown in top table; Accompanying *t*-statistics in bottom table)

		DAY	HOURS	YEAR GROUPS				
GROUP	TEMP INDEX	FRIDAY	14–16	1999–2001	2002–2004	2006–2007	2008	2009–2010
Top 100	795	–1663	993	–737	288	4974	2372	4
Top 200	891	–1372	870	–165	2783	7334	4702	2109
Top 300	960	–1577	1802	109	2892	7662	4184	2327
Top 400	1082	–1499	1727	390	3208	8260	4635	2594
Top 500	1077	–1403	1831	562	3149	8548	5089	2935
Top 600	1184	–1420	1763	409	3191	8761	4998	2860
Top 700	1247	–1419	2264	345	3119	8794	4976	2668
Top 800	1362	–1544	2316	563	3610	9083	5364	2834
Top 900	1420	–1559	2202	760	3842	9417	5598	2790
Top 1000	1478	–1609	2230	885	3750	9603	5857	2881
Top 1100	1561	–1655	2607	1201	3821	9942	6152	3063

		DAY	HOURS	YEAR GROUPS				
GROUP	TEMP INDEX	FRIDAY	14-16	1999–2001	2002–2004	2006–2007	2008	2009–2010
Top 100	7.78	–3.65	1.2	0.0		4.0	1.8	0.0
Top 200	14.41	–4.06	1.7		2.0	5.8	3.6	1.7
Top 300	17.84	–5.44	4.0	0.0	3.4	11.3	5.9	3.3
Top 400	24.40	–5.65	4.5	0.5	5.1	15.4	8.4	4.6
Top 500	26.06	–5.70	5.3	0.9	5.9	18.1	10.4	5.9
Top 600	30.93	–6.09	5.4	0.8	6.4	19.3	10.8	6.0
Top 700	34.99	–6.23	7.5	0.7	6.3	19.1	10.6	5.6
Top 800	42.19	–6.98	8.0	1.2	7.9	21.4	12.4	6.4
Top 900	48.25	–7.21	8.1	1.8	8.9	23.0	13.4	6.6
Top 1000	53.08	–7.32	8.3	2.1	8.9	23.6	14.1	6.8
Top 1100	60.21	–7.06	9.4	2.8	8.8	23.3	14.4	7.0

While the above tables contain a welter of statistics, the main point of interest is the relationship between the daily maximum demands and temperature. For both sort types (of the regression results), the gradient of the daily temperature variable increases steadily as more (lower ranked) load days are added. For the load-based sort, the gradient of the Top 100 days is approximately 800kW per degree, and climbs steadily to approximately 1200kW/degree as the middle load days are reached. Similarly, for the temperature-based sort, the gradients start higher (approximately 900) and stay above this level until the last few, reaching approximately 1,600.

This is a key analysis point. The slope (gradient) defined as, load change with respect to a change in temperature, is higher at temperatures that are less than the highest temperatures. Essentially, during hot days, as the temperatures approach the peak levels, the rate of change (increase) in loads declines.[14] The reason underlying this behavior is that, within the residential class, a fairly large share of air conditioning units have reached the maximum output and cannot cool more, running at a 100% duty cycle prior to reaching peak temperatures. Implicitly, a comparatively high number of residential households have unsatisfied demand for spatial cooling.

The clear inference is that a larger share of residential households in the FPU Northwest service territory utilizes window air conditioners. This is surely because of comparatively modest levels of household incomes for the FPU Northwest region, detailed previously in Section III.A. In summary, lower incomes result in higher saturation of window air conditioners which in turn result in peak loads that tend to flatten out toward the highest temperature levels of very hot days. For this reason—essentially, differences in the underlying demographics and households between FPU Northwest and Gulf—imply that load research results drawn from Gulf Power are not applicable to FPU Northwest.

III.C: Analysis of System Load Factor and Residential Energy Shares, FPU Northwest

Load research samples provide an empirical basis for estimating class peak loads, as the true class peak load contribution is typically not observable. In the absence of load research, the problem can be cast as a matter of drawing viable inferences about the relationship between class energy and system peak loads. Specifically, does observed

[14] Essentially, the second derivative—i.e., the change in the rate of load change with respect to change in temperature—is negative.

class energy consumption, coupled with monthly peak loads and load factors, provide a basis to infer how class peak load shares have changed? This section focuses on this question.

Weather, Energy, and Loads: The analysis of class energy shares and load factors is complicated by sensitivity of monthly energy to weather, both at the peak and also across the month. Thus, the starting point is weather, energy, and peak load data, measured in monthly frequency. Daily peak loads of FPU Northwest are modeled as a function of temperature, the hour of the day, the day of the week, and year. Using regression analysis, we estimate the relationship between weather and energy/peak demands, observed monthly over eight years. Weather is normalized. Then, the energy/load-weather relationship is used to estimate weather normalized monthly energy sales and peak loads.[15]

Load Factor and Residential Energy Shares: The analysis of load factor-residential energy shares is based on time series data, consisting of 40 observations for the five summer months over 2001–2009 (2005 is excluded because of missing data). The model specification, Model 1, is linear, as follows:

[15] Since monthly usage is available by class, weather adjustments for monthly usage were made for each class, and then aggregated to obtain the weather-adjusted system monthly usage. For each of the five summer months, the average weather including cooling degree days (CDDs) and heating degree days (HDDs) across years was determined. The deviations from these month-specific averages were calculated for each month and year. The monthly deviations of observed weather from historical average weather are multiplied by the estimated gradient (regression slopes of CDDs and HDDs) of energy with respect to weather. Weather gradients are obtained from energy-weather regressions: class energy usage is regressed on income, price, and weather. Results for the residential class are presented in the table below. As shown, the statistical fit is generally good, especially for weather with t-statistics greater than 30. Not shown are key diagnostic statistics, including an *adjusted R-square* of 0.93, and a *standard error of the estimate* of approximately 2% of the average summer usage levels. These results have been reported to the Commission and Staff previously by Christensen Associates Energy Consulting.

VARIABLE	INCOME	PRICE	CDD	HDD	INTERCEPT
Beta	4.24	–132.1	1.59	1.91	–0.21
t-statistic	5.3	–8.3	35.8	32.0	0.0

Analysis for the residential class is of particular interest for two reasons: 1) the residential class accounts for much of the weather variation of system loads; 2) residential share was the focus of the load factor-share analysis discussed herein.

$$LoadFactor_{m,y} = \beta o + \beta_{share}ResiShare_{m,y} + \beta_{price}Price_{m,y} + \beta_i D_i + \varepsilon_{m,y} \qquad \text{Model 1}$$

The above equation defines the weather-adjusted load factor in month *m* and year *y* ($LoadFactor_{m,\,y}$) as a function of a set of right-hand side (rhs) variables that explain the statistical variation in load factor,[16] including:

- *Residential Shares:* The residential energy share of total sales for month *m* and year *y*. This is the main variable of interest with the corresponding coefficient, β_{share}.
- *Price:* Real price of electricity for month *m* and year *y*, with the corresponding coefficient, β_{price}.[17]
- *Seasonal Patterns:* D_i represents four binary variables *(i = May, June, July, August)* covering summer months in order to control for systematic variation across the summer season.[18] September is the omitted month and thus the base period against which the coefficients for the other months are estimated.[19] The coefficient of each month dummy, β_i, implicitly captures the difference in estimated intercepts between that month and the base period.[20]
- The term $\varepsilon_{m,y}$ is the error term for each month-year combination, representing all unspecified determinants of load factor.

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[16] Load Factor is the average hourly load relative to the peak load, and is calculated directly from the weather normalized hourly load data, as described above. However, the share data are based on billed energy, and are derived from billing data rather than calendar energy, and could thus 'lag' the load factor somewhat.

[17] The monthly price term is specified as a declining sum of digits distributed lag of real prices over the current and previous 11 months:

$$P_m = \sum \alpha_i p_{m-i},\ i = 0, \ldots, 11 \quad ; \text{where } \alpha_0 = 12/78,\ \alpha_1 = 11/78, \ldots, \alpha_{11} = 1/78,$$

Though stylized, this approach appears to adequately account for the tendency of economic actors to recognize and respond to (marginal) changes in monthly prices with some delay. The price series was prepared for and used in analyses previously reported to the Commission. The income data series is nominal dollar county income data reported by the BLS, converted to real terms using the Personal Consumption Index (PCI) and then normalized to the middle of the study period, 2005.

[18] A binary variable (dummy variable) assumes values 1 and 0, depending on whether a given observation belongs to the subgroup defined (in our case, summer months), or not, respectively. For example, the "May" dummy variable would assign a value of 1 to all observations that belong to May, and 0 for the other months. These monthly binaries enable us to use a single regression equation to represent multiple summer months, rather than estimating separate equation models for each month.

[19] If a constant term is included in the regression, we cannot include binaries for all five months ranging from May to September. Inclusion of five binary terms along with the intercept term would result in perfect multicollinearity, implying an exact linear relationship between the variables and thus precluding estimation of the coefficients associated with the variables.

[20] β_o denotes the intercept for September; thus, the intercept for other summer months, *i*, is $\beta_o + \beta_i$.

The objective of the analysis is to estimate the sign and magnitude of the coefficient β_{share}. In so doing, effect of changes in the residential energy share on load factor, if it exists, is so determined.

Previous analysis found that price and income metrics were the two primary economic drivers of class loads. Thus, while the preferred model specification is weather-normalized load factor as a function of residential shares, monthly dummies, price *and* income, identification issues preclude the estimation of such a model. That is, because residential loads (and hence shares) are direct functions of income and prices, the estimation process would implicitly solve for an exact relationship between shares, income, and prices, so estimates for all parameters cannot be obtained. As a consequence, price alone was included in the estimated model, since it appeared to be the stronger of the two candidate drivers (income, prices).[21]

There is some concern that the relationship between load factor and residential shares evolved over the course of the sample period, 2001–2009 and beyond. One approach to assess the stationary of the relationship is to estimate the model over two periods, 2001–2007 and 2008–2009. Such an approach isn't possible—at least for these timeframes—because of insufficient degrees of freedom for the 2nd period ('08–'09).[22] A second approach is to estimate the original model inclusive of a binary variable for the 2nd period ('08–'09), and interacting the share variable with the newly introduced binary.[23] The base category, in this case, is 2001–2007. We also include interactions between residential energy shares and the month binary variables. Although we have intermediate models (Models 2 and 3) that exclusively include interactions between shares and the year dummy, and shares and the month binaries, respectively, these are not shown in the main body of the report, but are contained in Appendix 1. The full model, Model 4, containing all interaction variables as specified above, is as follows:

[21] Since the data are time series, models were also estimated with *time* on the RHS in a linear form, though it proved to be statistically insignificant.

[22] Fewer degrees of freedom translate into reduced accuracy of estimates.

$$LoadFactor_{m,y} = \beta o + \beta_{share}ResiShare_{m,y} + \beta_{price}Price_{m,y} + \beta_i D_i + \beta_{0809}D_{2008\text{-}09} + \beta_{share0809}(ResiShare_{m,y} \, X \, D_{2008\text{-}09}) + \beta_{shareDi}\,(ResiShare_{m,y} \, X \, D_i) + \varepsilon_{m,y} \qquad \text{Model 4}$$

In the above model specification, β_{share} captures the effect of the residential energy share on load factor for the base period 2001–2007. The corresponding effect of residential energy shares for the second period is captured as the sum of β_{share} and $\beta_{share0809}$. Essentially, $\beta_{share0809}$ is the estimate of the *change* in the slope of residential energy share on load factor between these two time periods.

Table 18a depicts the three likely scenarios as described above for the effect of residential shares on the weather-adjusted load factor. The Base Case is a stylized example but uses values close to the FPU Northwest system, it assumes that initially the residential class share is 45% with a coincident load factor of 60%, while the rest of the customers have a 55% share with a 75% load factor. Equating share to (an arbitrary unit of) load, the average load is 45 MWh for residential customers and 55 MWh for the remaining customers times a constant that is about one half. This implies a residential peak demand of 75 MW, while the peak demand for the other customers is 73.3 MW. For the system as a whole, the average hourly load totals to 100 MWh, peak load is 148.3 MW, and the load factor is 67.42%.

Under Case 1, the decline in residential class energy sales is not matched with a corresponding decline in peak demands. Thus, holding energy and peak loads of the other classes constant, the declining residential energy share results in a lower load factor for FPU Northwest, as a whole. To illustrate, the energy for the residential class declines to 43 MWh while the peak load remains constant, thus resulting in the class load factor declining to 57.3%; system load factor declines to 66.23%. For this strawman position (Case 1) to hold, the estimated β_{share} coefficient would be positively signed.

Table 18a
Conditional Changes in Residential Energy Shares and Load Factors, and the Implications for the System Load Factor

VARIABLE	RESIDENTIAL SHARE	OTHERS SHARE	SYSTEM
Baseline Case:			
MWh Share	45	55	100
Load Factor	60%	75%	67.42%
MW*[24]	75	73.3	148.3
Case 1: Residential Peak Loads and Load Factor Decline			
MWh Share	43	57	100
Load Factor	57.3%	75%	66.23%
MW*	75	76.0	151.0
Case 2: Residential Peak Loads and Load Factor Constant			
MWh Share	43	57	100
Load Factor	60%	75%	67.72%
MW*	71.7	76.0	147.7
Case 3: Residential Peak Loads and Load Factor Rise			
MWh Share	43	57	100
Load Factor	62%	75%	68.80%
MW*	69.35	76.0	145.4
Case 4: Using Empirical Results: Load Factor Rises			
MWh Share	43	57	100
Load Factor	65.55%	75%	68.80%
MW*	65.60	76.0	141.6

In Case 2, residential load factor stays constant and peak demand declines to 71.7 MW, and other customers' energy and loads are the same as Case 1. System load factor increases marginally from 67.42% to 67.72%. Case 2 would be reflected in a negative coefficient on the residential share variable but with very small magnitude. Within the context of the load factor-residential energy share analysis, residential share would most

[24] The MWh share is used, for simplicity, as scaled to 100 for the system. Rather than have MW be the true megawatt number, the analysis treats the MWh value as an average per hour. If the actual MWh value is put in, then the appropriate megawatt value is obtained. However, in this analysis we are holding the non-residential load factor constant even though it will also be changing by some amount. Since we are focusing on the implications of the model of residential shares and system load factor (the observables), it is useful to abstract from other changes which in a sense 'net out' in aggregate because of the share framework, which imposes a summation to unity (or 100, which is an easier value to track).

likely provide comparatively weak explanatory influence, and would very likely not be statistically significant.

In Case 3, the residential load factor rises to 62%. Thus, peak load declines to 69.35 MW. Holding the parameters of the other classes unchanged, the system load factor increases more substantially, to 68.8%. As in Case 2, the sign on β_{share} (residential energy share) would also be negative, but the coefficient would be substantially larger in magnitude and the variable would have higher statistical significance.

The fourth case matches the estimated parameter from the model where the combined effects of the Shares variable of the period after 2007 totals 1.603. Taking a sensitivity analysis with one standard deviation above and below the point estimate (at 0.90 and 2.30) yields load factors of 63.5% and 67.6% respectively.

Table 18b
Case 4' Actual Shares in Baseline of 2001-2007, Load Factor from Gulf Load Research and Results from Model of System Peaks and Residential Energy Shares Applied to Shares from Last Analysis Year 2009

VARIABLE	RESIDENTIAL SHARE	OTHERS SHARE	SYSTEM
'True' Baseline Case:			
MWh Share	45.29	54.71	100
Load Factor	57.31%	75.19%	65.88%
MW*	78.52	73.15	151.7
Case 4': Using Empirical Results: : Load Factor Rises			
MWh Share	42.91	57.09	100
Load Factor	63.54%	75.19%	69.70%
MW*	67.53	75.93	143.47

Table 18b alters the stylized case by changing the Baseline, by putting in the load factors derived from Gulf Power's load research data; essentially, this case 'takes as given' that the load research data were appropriate for the earlier period through 2007. This implies that the residential load factor is 57.31% instead of 60% and the other (non-lighting) classes aggregate to 75.19%. Then the residential share from this earlier period is used, 45.29%.

Case 4 from Table 18a now is altered to 4' where the usage share for the end of the period (2009) of 42.91 is used. As with Case 4, the load factor for residential loads is then derived from the value of -1.603 that has been obtained from the regression analysis. This implies that the residential load factor is 63.54% and the aggregate load factor is 69.70%.

Analysis Results

Column 1 of Table 19 reports Model 1, as estimated. The table contains the coefficient estimates for all the variables included in the model. Diagnostic statistics regarding model fit (how well the model specification fits the proposed variables), including an adjusted R-square of 73%[25] and a significance level (*F*-statistic) of essentially 0, which implies that the variables are all jointly statistically significant.[26]

The estimated parameter of particular interest is the coefficient on the residential energy share variable, obtained from the analysis of real world experience of FPU Northwest. As Table 19 shows, the energy share coefficient is negative and statistically significant; a residential share decrease of 1% translates into a system load factor increase of 0.723%.[27]

[25] The R-square is a commonly used measure to assess the "goodness of fit" of an estimated model. It describes the percentage of variability in the dependent variable that is accounted for by the independent variables. To compare the R-square across model specifications with the same dependent variable, but which contain a different number of explanatory variables, we have to "adjust" the R-square by the degrees of freedom.

[26] The significance level of the *F*-statistic gives us the lowest probability with which we can fail to reject the null hypothesis that the independent variables do not statistically explain variation in the dependent variable. In our case, this probability of failing to reject the null is 0, giving us "confidence" to conclude that the included variables determine variation in system load factor.

[27] Since the residential shares variable and the load factor are expressed as proportions, they are independent of units and the estimated coefficients can be interpreted similarly to percentage changes.

Table 19
Estimated Model Results:
System Load Factor on Residential Energy Share

VARIABLES	COEFFICIENT, (t-statistic)	COEFFICIENT, (t-statistic)
Residential Energy Share	*-0.723* *(2.06)*	*-1.760* *(3.16)*
Share x $D_{2008\text{-}09}$		*0.157* *(0.34)*
Combined effect		***-1.603*** ***(2.28)***
$D_{2008\text{-}09}$		-0.09 (0.49)
Price	-0.28 (1.48)	-0.32 (0.83)
Intercept	0.98 (5.93)	1.41 (5.56)
May	-0.06 (4.55)	-0.59 (1.97)
June	-0.04 (4.19)	-0.59 (2.02)
July	0.04 (3.82)	-0.30 (0.82)
August	0.02 (1.77)	-0.79 (2.17)
Adjusted R-Squared	0.696	0.730
Significance Level of F-statistic (40 Obs)	1.73×10^{-8}	5.59×10^{-7}

1. Values shown in parentheses refer to t-statistics associated with the estimated coefficients.
2. Dependent variable is the weather-normalized, monthly system load factor.
3. September is the omitted month within the set of monthly binary variables.
4. F-statistic refers to the degree of significance, defined as the lowest level at which the null hypothesis that the set of explanatory variables fail to 'explain' variation in the dependent variable can be rejected..

The results for Model 4 are reported in Column 2 of Table 19.[28] Note that general statistical 'fit' (Adjusted R^2, F) of Model 4 improves, with respect to the original model specification, namely Model 1. Second, the price variable changes sign; price is specified

[28] For brevity of space, we have not reported the estimates of all included coefficients in Table 19. The interested reader can refer to Table 24 in Appendix 1 for a detailed tabulation of all coefficient estimates, across all four model specifications.

with interaction, and it is thus of no real consequence.[29] Third, residential energy share remains negative and significant, and is of a higher magnitude as compared to previous model specifications. In other words, for the period 2001–2007, if residential energy shares decreased by 1%, load factor increases by almost twofold. The sum of the coefficients on the shares variable and the interaction between shares and the year dummy gives us the total effect for 2008–09, an effect of magnitude –1.603. As shown in the table, we obtained the t-statistic for this linear combination of coefficients as 2.28, a value rendering the estimated coefficient ($\beta_{share} + \beta_{share0809}$) as statistically significant.

Thus, Case 1 is ruled out: Case 1 does not represent the energy and load behavior of the residential class served by FPU Northwest. This leaves us with Cases 2 and 3 to test (reference Table 18a above). Since the estimated coefficient is statistically significant, it would seem that the empirical results are close to Case 3. However, to conclude definitively, we have to assess the size of the coefficient; this is described below.[30]

[29] The change in the price variable indicates that the direct flexibility of the interaction of shares with the periods allows the price variable to stop being a proxy for any changes across periods. Of course, it is the fact that the price went up very substantially in the 2008–2009 period that was the key cause of the decline in the residential share.

[30] We also estimated a so-called naïve model that regresses system load factor on residential shares and price, in isolation of the monthly binary variables. The results from this regression are presented in the table below. Model fit is considerably weaker, with an adjusted R-Square statistic of only 28%. Additionally, the signs of the variables 'flip', which appears to tell a different, incorrect story.

VARIABLE	SHARE	PRICE	INTERCEPT
Beta	0.97	0.42	0.18
t-statistic	3.8	1.9	1.5

These results serve as a caution against using simple a model that conflates changes across seasons with changes over time. Such a model misses the changes in load factor and shares to evolve over time because these changes are dominated by the differences in load and usage across the months due to weather. A "partial fix" of this issue would be to normalize summer months to the same level of peak and average weather. However, such approach leads to very large adjustments for the months along the various weather gradients, and is most problematic for maximum demand where subtle inconsistencies in the concept of peak demand (*e.g.*, monthly or annual peak temperatures) create interpretation issues. In addition, residual systematic seasonal differences may remain present.

The comparisons of Cases 2 and 3 to the Baseline Case are summarized in Table 20 below, as follows:

- Column 1: change in residential energy share (–2% in each case);
- Column 2: change in system load factor (–1.19% for Case 1, 0.30% for Case 2, and 1.38% for Case 3);
- Column 3: ratio of the change in the system load factor wrt to the change in the residential class energy share (0.60 for Case 1, –0.15 for Case 2, and –0.69 for Case 3).

Table 20
Changes in System Load Factor as a Function of the Changes in the Residential Shares

Case	Changes From Base Case In:		Ratio: ΔSystem LF/ ΔShare
	Residential Share	System Load Factor	
Case 1	–2%	–1.19%	0.60
Case 2	–2%	0.30%	–0.15
Case 3	–2%	1.38%	–0.69
Case 4	–2%	3.21%	–1.603
Case 4'	–2.38%	3.82%	–1.603

As noted above, Case 1 is unequivocally ruled out, owing to the estimated coefficient being negatively signed. Reverting to Table 19, the estimated coefficients of the residential share variables in Equation 2 sum to –1.603. This value is substantially larger than the associated change for Case 3 (–0.69) seen in Table 20. While there are minor residual issues of comparability between the stylized cases and the empirical model estimates that involve cross product terms, the analyses provide substantial reason to doubt that reductions in monthly residential energy shares is not associated with reduced residential peak load class shares.

Finally, Case 4 results from matching the change in load factor to the level necessary to obtain the estimated impact "change in system load factor divided by change in residential share" which is -1.603. In this case, the system load factor increases by a very substantial 3.21% because the residential load factor has increased by 5.55% to 65.55%.

Case 4 is not quite the end of this analysis however, we add one last piece, Case 4'. Here we use the actual load factors for residential, 57.31%, and the rest of the system (sans lighting), 75.19%. Then the residential share is changed from its average during 2001-2007 of 45.29% (excluding lighting) to 42.91%. This 2.38 percentage point reduction is residential load share, combined with the results of the analysis of shares and load factor yields a net impact of an increase in the residential share from 57.31 to 63.54% (an increase of 5.23 percentage points) and an improvement in system load factor of 3.82% to 69.70.

In brief, changes in monthly energy share for the residential are highly likely to be associated with equivalent changes in contribution in monthly peak demands. Furthermore, the magnitude of these changes is very substantial and in keeping with parallel analysis using analysis of weather effects on peak loads for FPU-Northwest.

How does this set of results correspond with other measures of the system. A straightforward explanation is that customers are holding base load energy consumption constant while cutting back on weather-sensitive usage, especially at peak times. Table 21 and the two accompanying bar graphs below investigate this situation. As shown in Figure 8 below, in period 2001–2007, the changes for the residential energy shares were largest in Spring and Fall. The relative position reverses in the Figure 9, where the changes are concentrated in the weather-sensitive seasons and smaller in Spring and Fall.[31] Since the weather sensitive load is lowest in the swing seasons, these data are consistent with the case that the residential energy share changes, at least after 2007, are entirely within weather sensitive load, while the base load remains comparatively unchanged. Base load usage can have coincident load factors of approximately unity, while weather-driven load factors are much lower, especially in the winter when peak loads are large but the amount of heating on most days is modest.

[31] The two graphs use the same scaling of the changes on the vertical axes to allow direct comparisons to be made.

Table 21
Annual Rate of Change of Class Shares Divided by Share
2001–2007 and 2007–2009

SHARES	ANNUAL	SUMMER	WINTER	SPRING/FALL
2001–2007				
Residential	–0.60%	–0.70%	–0.22%	–1.01%
Small Commercial	–0.54%	–0.53%	–0.18%	–1.03%
Industrial and Large Commercial	0.65%	0.72%	0.22%	0.99%
2007–2009				
Residential	–1.82%	–1.66%	–2.47%	–1.00%
Small Commercial	–1.22%	–1.34%	–0.63%	–1.69%
Industrial and Large Commercial	1.90%	1.70%	2.92%	1.02%

Figure 8: Relative Changes 2001–2007 (Change in Shares/Shares 2007)

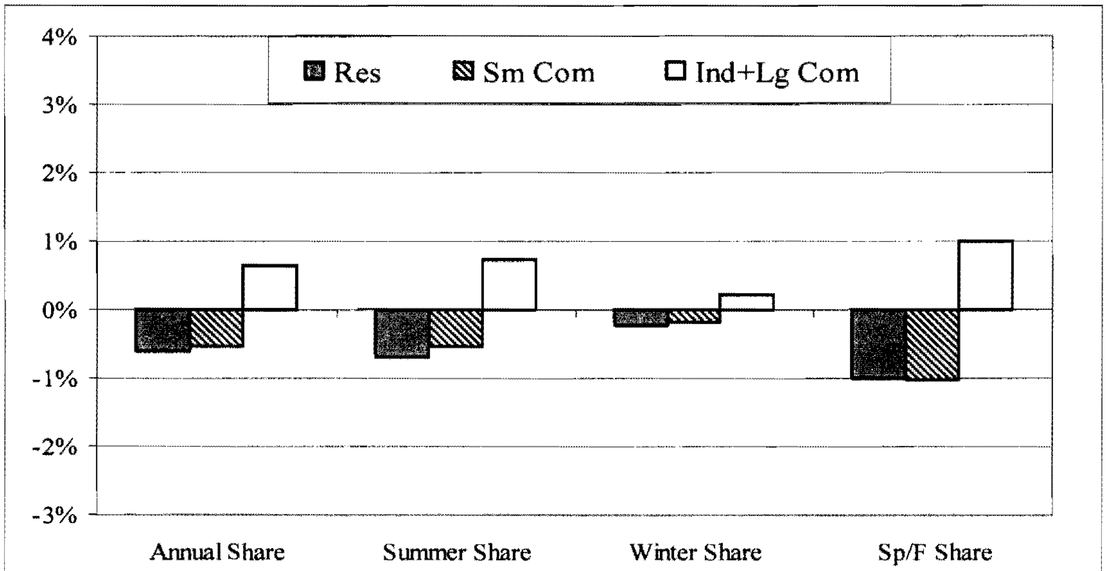
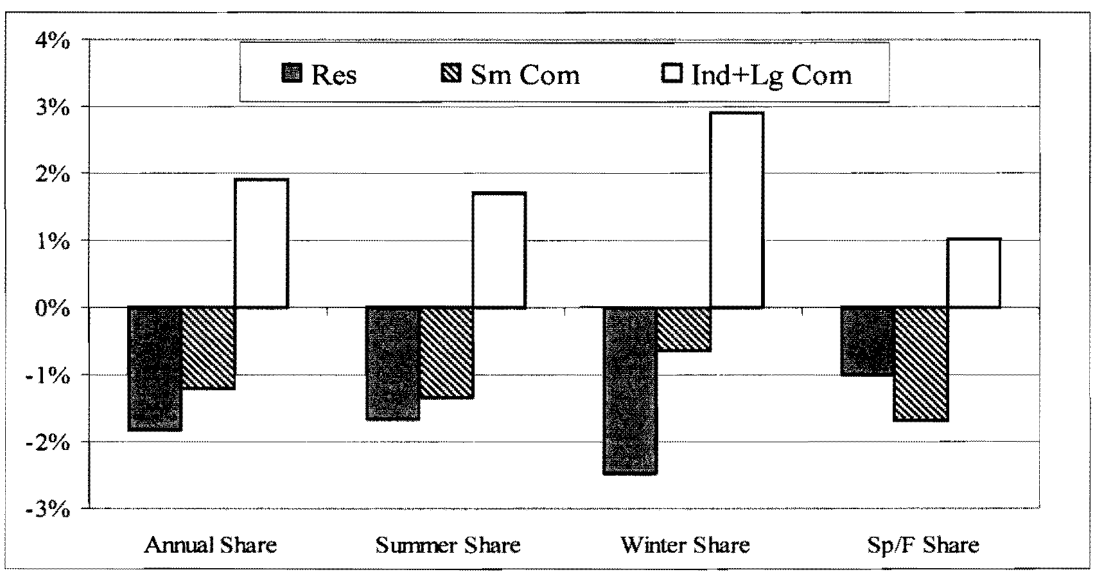


Figure 9: Relative Changes 2007–2009 (Change in Shares/Shares 2007)



IV. MATCHING UP BUSINESS CLASS LOAD FACTORS, GULF POWER LOAD RESEARCH TO FPU NORTHEAST AND NORTHWEST DIVISIONS

The application of load research of neighboring utilities should be managed with a degree of caution. The load and energy profiles across business classes vary because of differences in sector composition. Generally, weather sensitive loads are a smaller share of total energy for larger customers. The differences in weather sensitive load shares are implicit in observed load factors which are typically higher for larger customers (e.g., GSD, GSLD) than smaller business class customers (GS). Customers for a specific class vary of course from one utility to another. As a result, the class load factor of, say, the GSD class for one utility may be a good match to the underlying load experience of the GS class for a neighboring utility. Similarly, GSD for one may be reasonably well matched to GSLD of another.

To this end, we proposed match of business class load factors—i.e., Gulf Power to FPU Northeast and Northwest—is based on an analysis of weather sensitive and non-weather sensitive energy consumption. First, for GS, GSD, and GSLD customers, the ratio of average monthly energy for summer (June–September) and winter (December–February) to monthly energy for non-weather sensitive months (April–March, November) is determined. These results are presented below in Tables 22 and 23:

Table 22
Ratio of Weather Sensitive to Non-Weather Sensitive Energy, FPU Northeast and Gulf Power

	FPU Northeast		Gulf Power	
Residential	**S**	**W**	**S**	**W**
'01 - '10	1.44	1.23		
'00 - '11	1.48	1.27	1.60	1.29
GS	**S**	**W**	**S**	**W**
'01 - '10	1.30	1.11		
'00 - '11	1.31	1.13	1.43	1.18
GSD	**S**	**W**	**S**	**W**
'01 - '10	1.24	1.05		
'00 - '11	1.25	1.06	1.35	1.08
GSLD	**S**	**W**	**S**	**W**
'01 - '10	0.99	1.04	1.23	1.07
'00 - '11	0.99	1.03	1.21	1.03

Notes:
1) "S" refers to Summer; "W" refers to Winter.
2) Ratios for Gulf Power calculated from data shown in Gulf Power's MFR Schedules, Docket EL 110138.
3) For Gulf Power, GSLD includes LP (upper set) and LPT (lower set) classes.

Table 23
Ratio of Weather Sensitive to Non-Weather Sensitive Energy, FPU Northwest and Gulf Power

	FPU Northwest		Gulf Power	
Residential	**S**	**W**	**S**	**W**
'01 - '10	1.33	1.31		
'00 - '11	1.36	1.34	1.60	1.29
GS	**S**	**W**	**S**	**W**
'01 - '10	1.29	1.14		
'00 - '11	1.31	1.16	1.43	1.18
GSD	**S**	**W**	**S**	**W**
'01 - '10	1.27	1.09		
'00 - '11	1.27	1.10	1.35	1.08
GSLD	**S**	**W**	**S**	**W**
'01 - '10	1.23	1.08	1.23	1.07
'00 - '11	1.23	1.08	1.21	1.03

Notes:
1) "S" refers to Summer; "W" refers to Winter.
2) Ratios for Gulf Power calculated from data shown in Gulf Power's MFR Schedules, Docket EL 110138.
3) For Gulf Power, GSLD includes LP (upper set) and LPT (lower set) classes.

As shown above, across all classes, the ratios of weather sensitive energy to non weather sensitive energy for winter months are reasonably similar between FPU's divisions and Gulf Power Company. For summer months, however, the ratios of weather to non-weather sensitive monthly energy for GS, GSD, and GSLD classes reveal significant differences between FPU's two divisions and Gulf Power. Based on this evidence, we recommend that the load factors of Gulf Power's GSD business class be assigned to the GS class, for FPU Northeast and Northwest.

V. SUMMARY OF FINDINGS

Florida Public Utilities Company has historically relied on the load research of neighboring utilities (FPL, Gulf Power) as proxies of the load profiles of its Northeast and Northwest divisions, for the purposes of allocation of wholesale demand charges to the retail classes served. However, FPU has concerns about whether FPL and Gulf Power load research is sufficiently representative of the loads of FPU's retail customers, and thus the shares of system peak loads attributed to FPU customers. This report addresses this issue and, for FPU Northwest, presents analysis that can be used as the basis to infer the residential customer class contribution to peak loads, in the absence of estimated class load shapes specific to the customer classes of FPU. The first half of the report shows that, because of significant weather differences, FPL's load research is not likely to be a good proxy for the class load profiles of FPU Northeast. The latter half of the report demonstrates a possible bias in the relationship between class peak demand and energy when the Gulf load research is used as a proxy for FPU Northwest.

Our comparisons between FPU Northeast and FPL concentrates on the similarities and differences of weather for the underlying regions, reflected in heating and cooling degree day metrics (HDDs, CDDs). Daily weather data from 1990–2010 reveal striking differences in winter and summer weather patterns for the regions served by the two utilities. In terms of levels, we find markedly higher HDDs and somewhat lower CDD's for the FPU Northeast region than for the rather varied region served by FPL. In terms of temporal variation, we find that the average to peak ratio for HDDs is significantly lower for the FPL region than for the locale served by FPU Northeast. Conversely, for CDDs, the average to peak ratio for FPU Northeast is some 12%–20% lower, which implies that the difference between summer energy to peak demand, for residential customers in the Northeast, would be lower when compared to FPL.

For FPU Northwest, the study design follows two paths, and reaches clearly defined inferences about the underlying relationship between energy and peak loads. The study draws upon and analyzes county-level data over a 5-year period (2006–2010) from the American Community Survey, to compare the extent to which the regional economy of FPU Northwest matches that of Gulf Power. The Survey covers a wide range of demographic, housing, and economic dimensions. We find significant regional differences between the two utilities, notably in income levels, the proportion living below the poverty line, and in the housing stock. As compared to their Gulf Power counterparts, residential customers of FPU Northwest have lower household income, lower levels of educational attainment, and an older housing stock. We conclude from these findings that there is likely to be a greater prevalence of window air conditioner (A/C) units among the residences served by FPU Northwest than among residences of Gulf Power's region. This conclusion is verified by a fairly in-depth statistical analysis of peak loads and weather patterns, which shows concavity in the relationship between peak loads and temperature toward the top of the load-weather function. Because window A/C units typically run very near a 100% duty cycle prior to reaching peak temperatures, the clear implication is that, compared to residential loads of Gulf Power, residential loads for FPU Northwest are likely to be truncated at high temperatures, with a rising gap between desired and realized spatial cooling as temperatures reach exceptional levels.

The assessment also includes a model-based statistical analysis of system load factor and residential energy shares. The analysis is conducted with monthly frequency, covers summer months' data from 2001–2009, and controls for economic and weather determinants. A significant, negative relationship between weather normalized load factor and residential energy shares is found, and comports with logic-based cases of the change in class load factors and energy shares. Essentially, a decline in residential energy shares (which is the experience of FPU Northwest over recent years) translates directly into declines in peak demands; system load factor improves as the residential share decreases. In summary, we find that it is highly likely that, in the absence of appropriate adjustments, the use of Gulf Power load research will overstate the peak demand responsibility of FPU Northwest's residential customers.

APPENDIX 1
EXTENDED ANALYSIS OF LOAD FACTOR AND ENERGY SHARES

In addition to Models 1 and 4 outlined in Section III.C of the report, we also estimated two intermediate specifications. Model 2 below contains only an interaction term between the share variable and the year dummy, for the months, 2008 forward. The estimated specification is as follows:

$$LoadFactor_{m,y} = \beta_o + \beta_{share}ResiShare_{m,y} + \beta_{share0809}(ResiShare_{m,y} X\, D_{2008\text{-}09}) + \beta_{0809}D_{2008\text{-}09} + \beta_{price}Price_{m,y} + \beta_i D_i + \varepsilon_{m,y} \qquad \text{Model 2}$$

Empirical results of Model 2 are reported in Column 2 of Table 24 below. The coefficient on the shares variable increases somewhat, to –0.765, but remains negative and statistically significant. As described above, this is the effect of shares on load factor for the base category namely 2001–07. The positive sign on the interaction coefficient $ResiShare_{m,y} X\, D_{2008\text{-}09}$ implies that the negative relationship between residential shares and load factor is stronger for the period 2008–09. However, the value of the t-statistic implies that this change in the effect is statistically insignificant. The sum of the coefficients on the shares variable and the interaction between shares and the year dummy gives us the total effect for 2008–09, an effect of magnitude –0.564. Although not shown in the table, we obtained the t-statistic for this linear combination of coefficients as -1.29, a value rendering the estimated coefficient ($\beta_{share} + \beta_{share0809}$) as statistically insignificant.

The third specification we estimate, Model 3, includes interactions between residential energy share and the month binary variables. Model 3 specification is shown below:

$$LoadFactor_{m,y} = \beta o + \beta_{share}ResiShare_{m,y} + \beta_{price}Price_{m,y} + \beta_i D_i + \beta_{shareDi}\,(ResiShare_{m,y} X\, D_i) + \varepsilon_{m,y} \qquad \text{Model 3}$$

Table 24
Extended Analysis: System Load Factor on Residential Energy Share

VARIABLES	ORIGINAL MODEL (EQ 1)	MODEL 2	MODEL 3	MODEL 4
Share	*–0.723* *(2.06)*	*–0.765* *(2.14)*	*–1.744* *(3.07)*	*–1.760* *(3.16)*
Share x $D_{2008\text{-}09}$	–	*0.201* *(0.57)*	–	*0.157* *(0.34)*
Price	–0.28 (1.48)	0.31 (0.79)	–0.29 (1.58)	0.32 (0.83)
$D_{2008\text{-}09}$	–	–0.12 (0.76)	–	–0.09 (0.49)
Intercept	0.98 (5.93)	0.97 (5.74)	1.43 (5.57)	1.41 (5.56)
May	–0.06 (4.55)	–0.06 (4.48)	–0.64 (2.28)	–0.59 (1.97)
June	–0.04 (4.19)	–0.03 (4.12)	–0.58 (1.96)	–0.59 (2.02)
July	0.04 (3.82)	0.04 (3.91)	–0.28 (0.79)	–0.30 (0.82)
August	0.02 (1.77)	0.02 (1.80)	–0.77 (2.15)	–0.79 (2.17)
Share x May	–	–	1.32 (2.05)	1.24 (1.75)
Share x June	–	–	1.22 (1.84)	1.25 (1.91)
Share x July	–	–	0.73 (0.93)	0.77 (0.95)
Share x August	–	–	1.75 (2.21)	1.81 (2.23)
REGRESSION DIAGNOSTICS				
Adj. R-squared	0.696	0.705	0.719	0.730
F-statistic	1.73×10^{-8}	7.29×10^{-8}	2.02×10^{-7}	5.59×10^{-7}

1. Values shown in parentheses are *t*-statistics of the estimated coefficients.
2. Dependent variable is the weather-normalized, monthly system load factor.
3. September is the omitted month.
4. The *F*-statistic is the lowest significance level at which we can reject the null hypothesis that the set of explanatory variables fail to 'explain' variation of the dependent variable.

The empirical results of Model 3 are reported in Column 3 of Table 24. Again, the coefficient on residential shares remains negative and statistically significant, and grows considerably in magnitude.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2013 Projection Testimony of
Cheryl Martin
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Cheryl Martin, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company (FPUC) as the Director of Regulatory Affairs for the Company.

Q. Can you please provide a brief overview of your educational and employment background?

A. I have been employed by FPUC since 1985 and performed numerous accounting and regulatory roles and functions including regulatory accounting (Fuel, PGA, conservation, rate proceedings, Surveillance reports, regulatory reporting), tax accounting, external reports, corporate accounting and Florida accounting. In August 2011 I was promoted to my current position of Director of Regulatory Affairs. I have been an expert witness for numerous proceedings before the Florida Public Service Commission (FPSC). I graduated from Florida State University in 1984 with a BS degree in Accounting. Also, I am a Certified Public Accountant in the state of Florida.

Q. Have you previously testified in this Docket?

A. Yes. I have provided testimony in this proceeding on behalf of Florida Public Utilities on numerous occasions in past years.

Q. What is the purpose of your testimony at this time?

A. To discuss the reasons that "other fuel costs" are appropriate for inclusion in the fuel cost recovery clause and fuel rates.

Q. In Curtis Young's testimony he stated that the Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts, other fuel related work and legal representation outside of costs already embedded in the Company's base rates; please explain why these costs are recoverable through the fuel clause?

A. By Order No. 14546, in Docket No. 850001-EI-B, issued July 8, 1985, specific criteria was set forth for establishing the type of expense eligible for recovery through the fuel and purchased power cost recovery clause. Subsequently on December 23, 2005, the Commission, through Order No. PSC-05-1252-FOF-EI in Docket No. 050001-EI, approved recovery of the consulting fees paid to Christensen and Associates for the design of the RFP and subsequent evaluation of the responses through the fuel clause mechanism. Consistent with the Commission's policy, the costs included in the fuel clause are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts, which were unanticipated in the Company's last rate case, and which, consequently, tend to be more volatile depending upon the issue. The projected costs associated with legal and consulting work included in this filing are similar to the consulting fees approved through the aforementioned Order and to costs approved for recovery in the Company's prior years' true-ups in that they are directly related to fuel costs and the fuel clause, were not routine expenses nor were they included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Q. Specifically, what were the costs outside of purchased fuel costs included in the prior years' true-up for FPUC and deemed recoverable in the fuel clause?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. and Christensen and Associates for assistance in the development and enactment of three projects/programs designed to reduce fuel rates to its customers. The Company had separate types of administrative costs included in the true-up for the Northwest Division and Northeast Division.

Northwest Division-Other

The costs associated with the legal and consulting work on the Purchased Power Amendment are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPUC purchases all of its power requirements for its Northwest Division from Gulf Power. FPUC was able to negotiate changes in the PPA with Gulf Power that have resulted in substantial and measurable fuel savings (approximately $6 million), over the remaining term of the agreement, to the Northwest Division customers. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

As a result of the above-described PPA Amendment and the resultant demand savings, the Company was able to develop and gain approval of certain time-of-use and interruptible rates. As such, these two items, the PPA Amendment and TOU/Interruptible rates, are inextricably linked. As such, the costs associated with legal and consulting work on the development of the time-of-use (TOU) and interruptible rates are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPU's time of use and interruptible rates, as designed and approved, have two purposes: 1) to determine how the substantial PPA Amendment savings get allocated to customers, both those that voluntarily select the TOU/Interruptible rates and those who remain on the levelized fuel rates; and 2) to preserve the savings achieved by the PPA Amendment. TOU and interruptible rates exist precisely to reduce peak demands on the system and therefore are specifically implemented to ensure that the PPA Amendment savings are sustainable. Base rates were not affected by the TOU/Interruptible rates. As such, the legal and consulting expenses are solely and directly related to the fuel costs and therefore should be recovered through the Fuel and Purchased Power cost recovery clause. Moreover, these costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Additionally, The TOU and interruptible rates and the related rate savings derived from the PPA Amendment are available only to Northwest Division customers and the fuel clause provides for recovery of the TOU and interruptible rate related costs from the fuel rates approved for the Northwest Division customers.

Northeast Division-Other

The legal and consulting costs associated with the development and negotiations of the renewable energy contract are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. The Rayonier renewable energy contract, finalized and approved by PSC

Order earlier this year, provides for the purchase of power at rates lower than the existing Purchase Power Agreement between FPUC and JEA. FPUC expects to realize reduced fuel rates for the Northeast Division customers as a result of this agreement. These savings have been included in the 2013 Projections. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2013 Projection Testimony of
Curtis D. Young
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis D. Young, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that the Company has submitted in support of the January 2013 - December 2013 fuel cost recovery adjustments for its two electric divisions. In addition, I will explain the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2012 – December 2012 and to establish a "true-up" amount to be collected or refunded during January 2013 - December 2013.

Q. Were the schedules filed by the Company completed by you?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed for approval in this Docket?

A. The Company has filed Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and E1, E1A, E2, E7, E8, and E10 for the Northeast Division. Composite Exhibit Number CDY-4 contains this information.

Q. Did you follow the same procedures that were used in the prior period filings in preparing the projected cost factors for January – December 2013 for both the Northwest and Northeast Divisions?

A. Yes, the Company has generally used the same methodology as in prior period filings; however, in this filing it has made some changes in the process. The Company had, in previous filings, utilized data for the Northeast Division that was obtained from a 2010 Florida Power and Light ("FP&L") Load Research Study to allocate demand costs to the various

Northeast Division rate classifications. Similarly, the Company had utilized 2009 Load Research Study data obtained from Gulf Power to allocate demand costs to the various Northwest Division rate classifications. As is further explained in this testimony, the Company has adopted a more representative method for allocating costs to the rate classifications for each Division.

<u>Northwest Division</u>

<u>Purchased Power Amendment (PPA) with Gulf Power Company</u>

Q. Has the Company included any additional Schedules for consideration and possible approval in this Docket?

A. Yes, the Company has also included and prepared a set of additional Schedules in Composite Exhibit Number CDY-5 for its NW division only.

Q. For what purpose were these additional Schedules in Composite Exhibit Number CDY-5 being included?

A. The Schedules herein for the Northwest Division Composite Exhibit Number CDY-5 were prepared in light of the City of Marianna's ("City") appeal, filed with the Florida Supreme Court, of the Commission's Order(s) approving Amendment 1 to the Company's Purchased Power Agreement (PPA) with Gulf Power, PAA Order PSC-11-0269-PAA-EI, Order PSC-12-0056-FOF-EI, and Order PSC-12-0081-CO-EI. The Amendment reduces the monthly KW Peak Demand level and resultant costs while extending the Gulf Power Contract for two additional years. Because the status of the Amendment remains uncertain due to the City's appeal, Gulf Power is currently billing the Company at the original calculated Demand level until the Supreme Court has ruled on the City's appeal of the Commission's Order, or the matter is otherwise resolved in a manner that affirms and preserves the Amendment. The City's appeal of the Commission's Order disputes the benefits of the Amendment and its prudency for purposes of cost recovery. The City's appeal is also integrally tied to the City's separate appeal of the Commission's Order(s) (Order PSC-11-0112-TRF-EI, Order PSC-11-0290-FOF-EI, and Order PSC-12-0066-FOF-EI) approving the Company's implemented TOU and Interruptible Service rates, which are supported by the significant demand savings produced by the PPA with Gulf Power Company. The Schedules for Northwest Division Composite Exhibit Number CDY-5 present the Company's calculations of its fuel cost recovery factors based on the contingency that the PPA is ultimately reinstated before the hearing date in November 2012.

Q. What is the Company requesting with respect to this alternative set of Schedules and related fuel adjustment rates for its Northwest division?

A. The Company requests that the Commission review and consider these schedules for contingency approval if the legal proceedings regarding the Amendment to the Company's PPA with Gulf Power are resolved such that the Gulf Power contract, inclusive of the Amendment No. 1, is reinstated as of the original effective date of the Amendment. In addition, if the resolution of the referenced legal proceedings occurs after the hearing date in this Docket, but in the first half of 2013, the Company requests that the Commission consider these rates for purposes of a mid-course correction for the reduction of the rates to its customers in the NW division, including the customers within the city limits of Marianna. The midcourse correction for the reduction of rates would be immediately implemented as soon as practical, upon notice provided by the Company to the Commission of the Court's reinstatement of Amendment No. 1 as of the original effective date.

Northeast Division including Demand Allocation Method

Q. Please explain the methodology that the Company has used to calculate the Northeast Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northeast Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2013. The Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts, other fuel related work and legal representation outside of costs already embedded in the Company's base rates. The Company also projects the over or under recovered amount at the end of 2012. In addition, the Company projects its expected KWH sales to customers in 2013. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2013, as shown in Composite Exhibit Number CDY-4. As has historically occurred, the GSLD1 and Standby rate classifications are directly assigned its expected purchased power costs.

Q Why does the Company directly assign the GSLD1 and Standby rate classes purchased power costs?

A. The Company directly assigns the purchased power costs to the GSLD1 and Standby rate classifications' only two customers because they both have the capability to generate their own power. Both customers only purchase power sporadically from the Company, generally when they have an outage of their power generation facilities. It is not feasible to produce a levelized fuel rate for this rate classification that appropriately allocates costs. Demand and other purchased power costs are assigned to the GSLD1 and Standby rate classes directly based on their projected CP KW and KWH consumption. This procedure for the GSLD1 and Standby classes has been in use for several years and has not been changed herein. Costs to be recovered from all other Northeast Division rate classifications are determined after deducting from total purchased power costs those costs directly assigned to the GSLD1 and Standby rate classifications.

Q. Who does the Company purchase power from for the Northeast Division?

A. The Company purchases power from Jacksonville Electric Authority ("JEA") for the Northeast Division. Effective January 1, 2008, the Company executed an Amended and Restated Electric Service Contract with JEA (the "JEA Contract") which has a term of ten years.

Q. What impact has the JEA Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northeast Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the JEA Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity and weather patterns unique to the Northeast Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized FP&L's 2010 Load Research Data, is no longer the most accurate basis for this purpose.

Q. What basis has the Company used to allocate the JEA demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting ("CA") to develop recommendations for a method to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company (the "CA Report"). The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Composite Exhibit Number CDY-4. The CA Report details the empirical data that forms the basis for the Company's conclusion that the FP&L Load Research Data is not the most accurate basis for use in allocating demand costs for the Northeast Division. The CA Report provides further empirical data that demonstrates that the Gulf Power load research data is a better fit for use to allocate demand costs for the Northeast Division, and is detailed in the testimony and related exhibit of Mr. Robert Camfield, consultant with CA.

<u>Northwest Division including Demand Allocation Method</u>

Q. Please explain the methodology that the Company has used to calculate the Northwest Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northwest Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2013. The Company also projects the over or under recovered amount at the end of 2012. The Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts and other fuel related work and legal representation outside of costs already embedded in the Company's base rates. In addition, the Company projects its expected KWH sales to customers in 2013. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2013, as shown in Composite Exhibit Number CDY-4 and CDY-5.

Q. Who does the Company purchase power from for the Northwest Division?

A. The Company purchases power from Gulf Power Company ("Gulf Power") for the Northwest Division. Effective January 1, 2008, the Company executed an Agreement for Generation Services Between Gulf Power Company and Florida Public Utilities Company with Gulf Power (the "Gulf Power Contract") which has a term of ten years. Composite Prehearing Identification Number CDY-4 contains cost information utilizing this Contract. On January 25, 2011, the Company entered into Amendment No. 1 to the Gulf Power Contract, which, among other things, reduced the KW Peak Demand provision while extending the Gulf Power Contract for two additional years. Composite Exhibit Number CDY-5 contains cost information utilizing this Amendment to the Contract. If this amendment is reinstated, the rates contained within this Exhibit will be more appropriate for the Northwest division's customers.

Q. What impact has the Gulf Power Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northwest Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the Gulf Power Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity, economic and demographic profiles of customers and weather patterns unique to the Northwest Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized Gulf Power's 2009 Load Research Data, is no longer the most reasonable basis for this purpose.

Q. What basis has the Company used to allocate the Gulf Power demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting ("CA") to develop recommendations for a method to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company. The Company continues to utilize Gulf Power's load Research Data, but has adjusted the application with use of a Statistical method to more appropriately reflect the weather patterns and the economic and demographic profiles unique to its customers as well as slightly changed the application of one group of customers within the study. The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Composite Exhibit Number CDY-4. and CDY-5. Further explanation of this method and the reasons that it is more appropriate to use the statistically adjusted Gulf Power's load research data as a base for use in the NW division, is provided in the testimony and related exhibit of Mr. Robert Camfield, consultant with CA.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2011 for both Divisions?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,316,601. The final remaining amount for the Northeast Division was an under-recovery of $545,737.

Q. What are the estimated true-up amounts for the period of January – December 2012?

A. In the Northwest Division, there is an estimated under-recovery of $187,139. The Northeast Division has an estimated over-recovery of $801,347.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2013 year?

A. The Company has determined that at the end of December 2012 based on six months actual and six months estimated. We will have under-recovered $1,503,740 in purchased power costs in our Northwest Division. Based on estimated sales for the period January - December 2013, it will be necessary to add .45374¢ per KWH to collect this under-recovery. In our Northeast division we will have over-recovered $255,610 in purchased power costs. This amount will be refunded at .07673¢ per KWH during the January - December 2013 period (excludes GSLD1 and Standby customers). Page 3 and 10 of Composite Exhibit Number CDY-4 provides detailed calculations of the respective true-up amounts.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period?

A. In the Northwest Division the total fuel adjustment factor as shown on Line 33, Schedule E-1 is 6.149¢ per KWH. In the Northeast Division the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E-1, is 6.420¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2013 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on Schedule E-10 in Composite Exhibit Number CDY-4, a residential customer in the Northwest Division using 1,000 KWH will pay $137.35, an increase of $2.71 from the previous period. In the Northeast Division a residential customer using 1,000 KWH will pay $134.40, an increase of $5.33 from the previous period.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2013 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier if the contract amendment is reinstated with Gulf Power Company.

A. Pending successful resolution between of the litigation between the City of Marianna, and the Company, as shown on Schedule E-10 in Composite Exhibit Number CDY-5, a residential customer in the Northwest Division using 1,000 KWH will pay $129.94, a decrease of $4.70 from the previous period.

Q. Are there any additional documents that the Company has included in this filing?

A. The Company has also included sets of additional Schedules in Composite Exhibit Number CDY-6 (NW division only) and CDY-7 (Northwest and Northeast divisions). These schedules have been included for informational purposes for the Commission staff's review. They are identical to Exhibits CDY-4 and CDY-5 except that they have been prepared to exclude the new methodology for allocating demand;

these schedules utilize the prior method approved for allocating demand. The Company has included these schedules to allow the Commission staff the ability to review the requested demand allocation methodology, and the related impact to customer's rates. The Company is not requesting approval of the rates associated with these two exhibits and feel the new demand allocation methodology is the more appropriate methodology for its customers and the fuel rates for 2013.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA PUBLIC UTILITIES COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION - **without Amendment 1, Demand Alloc rev**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA 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)	18,673,989		345,001	5.41273
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)	13,447,859		345,001	3.89792
10a	Demand Costs of Purchased Power	12,863,678	*		
10b	Transformation Energy & Customer Costs of Purchased Power	584,181	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	32,121,848		345,001	9.31065
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	32,121,848		345,001	9.31065
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)	32,121,848		345,001	9.31065
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,252	*	239	0.00671
23	T & D Losses	1,243,437	*	13,355	0.37520
24	SYSTEM MWH SALES	32,121,848		331,407	9.69257
25	Less Total Demand Cost Recovery	12,863,678	***		
26	Jurisdictional MWH Sales	19,258,170		331,407	5.81103
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	19,258,170		331,407	5.811030
28	Projected Unbilled Revenues	(400,000)		331,407	(0.120700)
29	TRUE-UP **	1,503,740		331,407	0.453740
30	TOTAL JURISDICTIONAL FUEL COST	20,361,910		331,407	6.144080
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.14850
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	20,376,570			6.149

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO.____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-4)

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER - **Without Amendment 1, Demand Alloc rev**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(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	144,617,000	62.896%	26,247.8	1.089	1.030	28,583.9	148,955,510	49.04%	43.65%
35	GS	30,599,000	73.904%	4,726.5	1.089	1.030	5,147.2	31,516,970	8.83%	9.23%
36	GSD	90,797,000	73.904%	14,024.9	1.089	1.030	15,273.1	93,520,910	26.21%	27.40%
37	GSLD	60,298,000	84.021%	8,192.4	1.089	1.030	8,921.5	62,106,940	15.31%	18.19%
38	OL, OL1	3,954,000	178.492%	252.9	1.089	1.030	275.4	4,072,620	0.47%	1.19%
39	SL1, SL2 & SL3	1,142,000	178.492%	73.0	1.089	1.030	79.5	1,176,260	0.14%	0.34%
40	TOTAL	331,407,000		53,517.5			58,280.6	341,349,210	100.00%	100.00%

		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		12/13 * (8)	1/13 * (9)	(10) + (11)	Tot. Col. 13 * (12	(13)/(1)	(14) * 1.00072		(15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	45.26%	3.37%	48.63%	$6,255,607	0.04326	0.04329	0.06149	$0.10478
42	GS	8.15%	0.71%	8.86%	1,139,722	0.03725	0.03728	0.06149	$0.09877
43	GSD	24.19%	2.11%	26.30%	3,383,147	0.03726	0.03729	0.06149	$0.09878
44	GSLD	14.13%	1.40%	15.53%	1,997,729	0.03313	0.03315	0.06149	$0.09464
45	OL, OL1	0.43%	0.09%	0.52%	66,891	0.01692	0.01693	0.06149	$0.07842
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%	20,582	0.01802	0.01803	0.06149	$0.07952
47	TOTAL	92.29%	7.71%	100.00%	$12,863,678				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21)
					(19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	144,617,000	$0.10478	$15,152,969
49	RS	<= 1,000kWh/mo.	92,734,000	$0.10119	$9,383,975
50	RS	> 1,000 kWh/mo.	51,883,000	$0.11119	$5,768,995
51	RS	Total Sales	144,617,000		$15,152,969

TOU Rates

		(22)	(23)	(24)	(25)
	Rate Schedule	On Peak Rate Differential	Off Peak Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
52	RS	0.0840	(0.0390)	$0.18519	$0.06219
53	GS	0.0400	(0.0500)	$0.13877	$0.04877
54	GSD	0.0400	(0.0325)	$0.13878	$0.06628
55	GSLD	0.0600	(0.0300)	$0.15464	$0.06464
56	Interruptibl	(0.0150)	-	$0.07964	$0.09464

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD - **Without Amendment 1, Demand Alloc rev**
JANUARY 2012 - DECEMBER 2012
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2012 - December 2012. (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 2012; (Estimated)	$	1,503,740
Estimated kilowatt hour sales for the months of January 2013 - December 2013 as per estimate filed with the Commission.		331,407,000
Cents per kilowatt hour necessary to collection under-recovered purchased power costs over the period January 2013 - December 2013.		0.45374

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION - **Without Amendment 1, Demand Alloc rev**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

LINE NO.		(a) 2013 JANUARY	(b) 2013 FEBRUARY	(c) 2013 MARCH	(d) 2013 APRIL	(e) 2013 MAY	(f) 2013 JUNE	(g) 2013 JULY	(h) 2013 AUGUST	(i) 2013 SEPTEMBER	(j) 2013 OCTOBER	(k) 2013 NOVEMBER	(l) 2013 DECEMBER	(m) 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	1,614,262	1,544,125	1,493,593	1,265,996	1,348,952	1,671,750	1,792,733	1,812,048	1,737,157	1,600,356	1,332,782	1,460,235	18,673,989	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,165,203	1,130,448	1,081,200	1,092,847	1,121,227	1,141,587	1,134,149	1,138,687	1,128,259	1,102,900	1,087,439	1,123,913	13,447,859	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)	2,779,465	2,674,573	2,574,793	2,358,843	2,470,179	2,813,337	2,926,882	2,950,735	2,865,416	2,703,256	2,420,221	2,584,148	32,121,848	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,116,440	1,081,783	1,032,606	1,044,570	1,072,834	1,092,744	1,085,137	1,089,648	1,079,325	1,054,157	1,039,069	1,075,365	12,863,678	6
7	TOTAL OTHER COST TO BE RECOVERED	1,663,025	1,592,790	1,542,187	1,314,273	1,397,345	1,720,593	1,841,745	1,861,087	1,786,091	1,649,099	1,381,152	1,508,783	19,258,170	7
7a	SYSTEM KWH SOLD (MWH)	28,094	26,874	25,995	22,036	23,479	29,094	32,140	32,868	31,410	28,929	24,092	26,396	331,407	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.9195	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.7005	5.73282	5.71595	5.81103	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)	5.91950	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.70050	5.73282	5.71595	5.81103	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	10
11	TRUE-UP (CENTS/KWH)	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	11
12	TOTAL	6.25254	6.25992	6.26567	6.29725	6.28451	6.24695	6.06342	5.99535	6.01942	6.03354	6.06586	6.04899	6.14408	12
13	REVENUE TAX FACTOR 0.00072	0.00450	0.00451	0.00451	0.00453	0.00452	0.00450	0.00437	0.00432	0.00433	0.00434	0.00437	0.00436	0.00442	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	6.25704	6.26443	6.27018	6.30178	6.28903	6.25145	6.06779	5.99967	6.02375	6.03788	6.07023	6.05335	6.14850	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	6.257	6.264	6.270	6.302	6.289	6.251	6.068	6.000	6.024	6.038	6.070	6.053	6.149	15

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER

(EXCLUSIVE OF ECONOMY ENERGY PURCHASES) - **without Amendment 1, Demand Alloc rev**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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	2013	GULF POWER COMPANY	RE	29,823,425			29,823,425	5.412732	9.299619	1,614,262
FEBRUARY	2013	GULF POWER COMPANY	RE	28,527,660			28,527,660	5.412729	9.354335	1,544,125
MARCH	2013	GULF POWER COMPANY	RE	27,594,076			27,594,076	5.412732	9.309219	1,493,593
APRIL	2013	GULF POWER COMPANY	RE	23,389,223			23,389,223	5.412732	10.059518	1,265,996
MAY	2013	GULF POWER COMPANY	RE	24,921,830			24,921,830	5.412732	9.887633	1,348,952
JUNE	2013	GULF POWER COMPANY	RE	30,885,524			30,885,524	5.412729	9.089491	1,671,750
JULY	2013	GULF POWER COMPANY	RE	33,120,681			33,120,681	5.412731	8.818907	1,792,733
AUGUST	2013	GULF POWER COMPANY	RE	33,477,525			33,477,525	5.412731	8.796155	1,812,048
SEPTEMBER	2013	GULF POWER COMPANY	RE	32,093,915			32,093,915	5.412730	8.909527	1,737,157
OCTOBER	2013	GULF POWER COMPANY	RE	29,566,500			29,566,500	5.412729	9.122673	1,600,356
NOVEMBER	2013	GULF POWER COMPANY	RE	24,623,100			24,623,100	5.412728	9.804700	1,332,782
DECEMBER	2013	GULF POWER COMPANY	RE	26,977,780			26,977,780	5.412730	9.556561	1,460,235
TOTAL				345,001,239	0	0	345,001,239	5.412731	9.289777	18,673,989

EXHIBIT NO. __________
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FLORIDA PUBLIC UTILITIES COMPANY
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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON - **without Amendment 1, Demand Alloc rev**
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	10.12	10.12	10.12	10.12	10.12	10.12	10.12
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	101.19	101.19	101.19	101.19	101.19	101.19	101.19
GROSS RECEIPTS TAX	3.43	3.43	3.43	3.43	3.43	3.43	3.43
TOTAL REVENUES *** $	137.35	137.35	137.35	137.35	137.35	137.35	137.35

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	10.12	10.12	10.12	10.12	10.12	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	101.19	101.19	101.19	101.19	101.19	1,214.28
GROSS RECEIPTS TAX	3.43	3.43	3.43	3.43	3.43	41.16
TOTAL REVENUES *** $	137.35	137.35	137.35	137.35	137.35	1,648.20

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC UTILITIES COMPANY
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FLORIDA PUBLIC UTILITIES COMPANY

FUEL AND PURCHASED POWER

COST RECOVERY CLAUSE CALCULATION - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	NORTHEAST FLORIDA DIVISION	(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)	15,234,865	349,424	4.35999
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)	19,325,396	349,424	5.53064
10a	Demand Costs of Purchased Power	12,867,536 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	6,457,860 *		
11	Energy Payments to Qualifying Facilities (E8a)	1,469,762	23,770	6.18326
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	36,030,023	373,194	9.65450
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	36,030,023	373,194	9.65450
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)	36,030,023	373,194	9.65450
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	43,156 *	447	0.01208
23	T & D Losses	1,508,419 *	15,624	0.42238
24	SYSTEM MWH SALES	36,030,023	357,123	10.08897
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	36,030,023	357,123	10.08897
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	36,030,023	357,123	10.08897
27a	GSLD1 MWH Sales		24,000	
27b	Other Classes MWH Sales		333,123	
27c	GSLD1 CP KW		456,000 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	(255,610)	357,123	-0.07157
30	TOTAL JURISDICTIONAL FUEL COST	35,774,413	357,123	10.01739
30a	Demand Purchased Power Costs (Line 10a)	12,867,536 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	23,162,487 *		
30c	True up Over/Under Recovery (Line 29)	(255,610) *		

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. __________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-4)

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	12,867,536		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	1,563,169	456,000 (KW)	$3.43 /KW
33	Balance to Other Classes	11,304,367	333,123	3.39345
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	23,162,487		
35	Total KWH Purchased (Line 12)		373,194	
36	Average Cost per KWH Purchased			6.20655
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			6.39714
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,535,313	24,000	6.39714
39	Balance to Other Classes	21,627,174	333,123	6.49225
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,563,169	456,000 (KW)	$3.43 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$3.43 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,535,313	24,000	6.39714
40e	Total Non-demand Costs Including True-up	1,535,313	24,000	6.39714
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			6.40175
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	32,931,541	333,123	9.88570
41b	Less: Total Demand Cost Recovery	11,304,367 ***		
41c	Total Other Costs to be Recovered	21,627,174	333,123	6.49225
41d	Other Classes' Portion of True-up (Line 30c)	(255,610)	333,123	-0.07673
41e	Total Demand & Non-demand Costs Including True-up	21,371,564	333,123	6.41552
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	21,386,952		6.420

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

NORTHEAST FLORIDA DIVISION

	Rate Schedule	(1) KWH Sales	(2) 12 CP Load Factor	(3) (1)/((2)*8,760) CP KW At Meter	(4) Demand Loss Factor	(5) Energy Loss Factor	(6) (3)*(4) CP KW At GEN.	(7) (1)*(5) KWH At GEN.	(8) (6)/Total Col. (6) 12 CP Demand Percentage	(9) (7)/Total Col. (7) Energy Percentage
44	RS	189,516,000	57.313%	37,747.5	1.089	1.030	41,107.0	195,201,480	63.91%	56.89%
45	GS	29,082,000	73.904%	4,492.1	1.089	1.030	4,891.9	29,954,460	7.61%	8.73%
46	GSD	86,323,000	73.904%	13,333.8	1.089	1.030	14,520.5	88,912,690	22.58%	25.91%
47	GSLD	25,652,000	84.022%	3,485.2	1.089	1.030	3,795.4	26,421,560	5.90%	7.70%
48	OL	1,416,000	4996.200%	3.2	1.089	1.030	3.5	1,458,480	0.01%	0.43%
49	SL	1,134,000	4996.200%	2.6	1.089	1.030	2.8	1,168,020	0.00%	0.34%
	TOTAL	333,123,000		59,064.4			64,321.1	343,116,690	100.01%	100.00%

	Rate Schedule	(10) 12/13 * (8) 12/13 Of 12 CP	(11) 1/13 * (9) 1/13 Of Energy	(12) (10) + (11) Demand Allocation Percentage	(13) Tot. Col. 13 * (9) Demand Dollars	(14) (13)/(1) Demand Cost Recovery	(15) (14) * 1.00072 Demand Cost Recovery Adj for Taxes	(16) Other Charges	(17) (15) + (16) Levelized Adjustment
50	RS	58.99%	4.38%	63.37%	$7,163,577	0.03780	0.03783	0.06420	0.10203
51	GS	7.02%	0.67%	7.69%	869,306	0.02989	0.02991	0.06420	0.09411
52	GSD	20.84%	1.99%	22.83%	2,580,787	0.02990	0.02992	0.06420	0.09412
53	GSLD	5.45%	0.59%	6.04%	682,784	0.02662	0.02664	0.06420	0.09084
54	OL	0.01%	0.03%	0.04%	4,522	0.00319	0.00319	0.06420	0.06739
55	SL	0.00%	0.03%	0.03%	3,391	0.00299	0.00299	0.06420	0.06719
	TOTAL	92.31%	7.69%	100.00%	$11,304,367				

Step Rate Allocation for Residential Customers

	Rate Schedule	(18) Allocation	(19) Annual kWh	(20) Levelized Adj.	(21) (19) * (20) Revenues
48	RS	Sales	189,516,000	$0.10203	$19,336,317
49	RS	<= 1,000kWh/mo.	119,001,000	$0.09831	$11,698,894
50	RS	> 1,000 kWh/mo.	70,515,000	$0.10831	$7,637,424
51	RS	Total Sales	189,516,000		$19,336,317

(2) From Florida Power & Light Co. 2010 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD - **with Demand Allocation**
JANUARY 2012 - DECEMBER 2012
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Over-recovery of purchased power costs for the period January 2012 - December 2012. (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 2012.)(Estimated)	$	(255,610)
Estimated kilowatt hour sales for the months of January 2013-December 2013 as per estimate filed with the Commission. (Excludes GSLD1 customers)		333,123,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2013 - December 2013		-0.07673

FLORIDA PUBLIC UTILITIES COMPANY

NORTHEAST FLORIDA DIVISION

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

			(a)	(b)	(c)	(d)	(e)	(f)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
								ESTIMATED								
LINE NO.			JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	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		1,158,297	1,187,177	1,134,286	1,019,911	1,087,812	1,352,787	1,667,301	1,601,237	1,518,587	1,352,012	1,098,323	1,057,135	15,234,865	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,711,651	1,743,692	1,381,372	1,395,187	1,503,724	1,746,691	1,871,457	1,857,850	1,712,923	1,549,598	1,333,551	1,517,700	19,325,396	3a
3b	QUALIFYING FACILITIES		128,399	85,625	128,399	125,435	132,498	125,435	125,435	125,435	125,435	125,435	120,622	121,609	1,469,762	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,998,347	3,016,494	2,644,057	2,540,533	2,724,034	3,224,913	3,664,193	3,584,522	3,356,945	3,027,045	2,552,496	2,696,444	36,030,023	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,085,164	1,106,322	763,934	820,849	903,798	1,046,914	1,053,160	1,064,448	950,666	850,113	729,665	929,335	11,304,367	5a
5b	TOTAL OTHER COST TO BE RECOVERED		1,913,183	1,910,172	1,880,123	1,719,684	1,820,236	2,177,999	2,611,033	2,520,074	2,406,279	2,176,932	1,822,831	1,767,109	24,725,656	5b
6	APPORTIONMENT TO GSLD1 CLASS		258,387	258,026	258,474	259,208	258,965	257,987	257,259	257,389	257,568	257,989	258,494	258,736	3,098,482	6
6a	BALANCE TO OTHER CLASSES		1,654,797	1,652,146	1,621,649	1,460,476	1,561,271	1,920,012	2,353,774	2,262,685	2,148,711	1,918,943	1,564,337	1,508,373	21,627,174	6a
6b	SYSTEM KWH SOLD (MWH)		27,432	27,463	26,905	24,299	25,885	31,605	38,508	37,058	35,244	31,588	26,020	25,116	357,123	6b
7	GSLD1 MWH SOLD		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	7
7a	BALANCE MWH SOLD OTHER CLASSES		25,432	25,463	24,905	22,299	23,885	29,605	36,508	35,058	33,244	29,588	24,020	23,116	333,123	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.50675	6.48842	6.51134	6.54951	6.53662	6.48543	6.44728	6.45412	6.46346	6.48554	6.51264	6.52523	6.49225	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)		6.50675	6.48842	6.51134	6.54951	6.53662	6.48543	6.44728	6.45412	6.46346	6.48554	6.51264	6.52523	6.49225	9
10	GPIF ** (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	(255,610)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	11
12	TOTAL		6.43002	6.41169	6.43461	6.47278	6.45989	6.40870	6.37055	6.37739	6.38673	6.40881	6.43591	6.44850	6.41552	12
13	REVENUE TAX FACTOR	0.00072	0.00463	0.00462	0.00463	0.00466	0.00465	0.00461	0.00459	0.00459	0.00460	0.00461	0.00463	0.00464	0.00462	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.43465	6.41631	6.43924	6.47744	6.46454	6.41331	6.37514	6.38198	6.39133	6.41342	6.44054	6.45314	6.42014	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.435	6.416	6.439	6.477	6.465	6.413	6.375	6.382	6.391	6.413	6.441	6.453	6.420	15

EXHIBIT NO. __________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-4)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES) - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)
								CENTS/KWH		
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	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	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,566,440			26,566,440	4.360001	11.110977	1,158,297
FEBRUARY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	27,228,835			27,228,835	4.359999	10.907327	1,187,177
MARCH	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,015,725			26,015,725	4.360001	9.984350	1,134,286
APRIL	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	23,392,455			23,392,455	4.360000	10.661459	1,019,911
MAY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,949,825			24,949,825	4.359999	10.731450	1,087,812
JUNE	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,027,225			31,027,225	4.360000	10.243768	1,352,787
JULY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,240,860			38,240,860	4.359999	9.460135	1,667,301
AUGUST	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,725,610			36,725,610	4.360001	9.633512	1,601,237
SEPTEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,829,980			34,829,980	4.360000	9.504424	1,518,587
OCTOBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,009,460			31,009,460	4.359999	9.611548	1,352,012
NOVEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	25,190,900			25,190,900	4.359999	9.947799	1,098,323
DECEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,246,220			24,246,220	4.359999	10.929077	1,057,135
TOTAL				349,423,535	0	0	349,423,535	4.360000	10.151391	15,234,865

EXHIBIT NO. __________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-4)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES - **with Demand Allocation**

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

(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	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.114238	6.114238	128,399
FEBRUARY	2013	ROCK TENN & RAYONIER		1,470,000			1,470,000	5.824830	5.824830	85,625
MARCH	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.114238	6.114238	128,399
APRIL	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
MAY	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.309429	6.309429	132,498
JUNE	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
JULY	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
AUGUST	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
SEPTEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
OCTOBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
NOVEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.031100	6.031100	120,622
DECEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.080450	6.080450	121,609
TOTAL				23,770,000	0	0	23,770,000	6.183265	6.183265	1,469,762

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON - with Demand Allocation

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	9.83	9.83	9.83	9.83	9.83	9.83	9.83
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	98.31	98.31	98.31	98.31	98.31	98.31	98.31
GROSS RECEIPTS TAX	3.36	3.36	3.36	3.36	3.36	3.36	3.36
TOTAL REVENUES *** $	134.40	134.40	134.40	134.40	134.40	134.40	134.40

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	9.83	9.83	9.83	9.83	9.83	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	98.31	98.31	98.31	98.31	98.31	1,179.72
GROSS RECEIPTS TAX	3.36	3.36	3.36	3.36	3.36	40.32
TOTAL REVENUES *** $	134.40	134.40	134.40	134.40	134.40	1,612.80

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. ________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-4)
PAGE 14 OF 14

FLORIDA PUBLIC UTILITIES COMPANY

FUEL AND PURCHASED POWER

COST RECOVERY CLAUSE CALCULATION - **with Amendment 1, Demand Alloc. Rev**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA 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)	18,673,989		345,001	5.41273
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)	12,656,243		345,001	3.66847
10a	Demand Costs of Purchased Power	12,072,062	*		
10b	Transformation Energy & Customer Costs of Purchased Power	584,181	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,330,232		345,001	9.08120
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,330,232		345,001	9.08120
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)	31,330,232		345,001	9.08120
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	21,704	*	239	0.00655
23	T & D Losses	1,212,794	*	13,355	0.36595
24	SYSTEM MWH SALES	31,330,232		331,407	9.45370
25	Less Total Demand Cost Recovery	12,072,062	***		
26	Jurisdictional MWH Sales	19,258,170		331,407	5.81103
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	19,258,170		331,407	5.81103
28	Projected Unbilled Revenues	(400,000)		331,407	(0.12070)
29	TRUE-UP **	(3,248)		331,407	(0.00098)
30	TOTAL JURISDICTIONAL FUEL COST	18,854,922		331,407	5.68936
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				5.69346
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	18,868,497			5.693

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO.____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-5)
PAGE 1 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER - **With Amendment 1, Demand Allocation rev**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(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	144,617,000	62.896%	26,247.8	1.089	1.030	28,583.9	148,955,510	49.04%	43.65%
35	GS	30,599,000	73.904%	4,726.5	1.089	1.030	5,147.2	31,516,970	8.83%	9.23%
36	GSD	90,797,000	73.904%	14,024.9	1.089	1.030	15,273.1	93,520,910	26.21%	27.40%
37	GSLD	60,298,000	84.021%	8,192.4	1.089	1.030	8,921.5	62,106,940	15.31%	18.19%
38	OL, OL1	3,954,000	178.492%	252.9	1.089	1.030	275.4	4,072,620	0.47%	1.19%
39	SL1, SL2 & SL3	1,142,000	178.492%	73.0	1.089	1.030	79.5	1,176,260	0.14%	0.34%
40	TOTAL	331,407,000		53,517.5			58,280.6	341,349,210	100.00%	100.00%

		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		12/13 * (8)	1/13 * (9)	(10) + (11)	Tot. Col. 13 * (12	(13)/(1)	(14) * 1.00072		(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
41	RS	45.26%	3.37%	48.63%	$5,870,644	0.04059	0.04062	0.05693	$0.09755
42	GS	8.15%	0.71%	8.86%	1,069,585	0.03495	0.03498	0.05693	$0.09191
43	GSD	24.19%	2.11%	26.30%	3,174,952	0.03497	0.03500	0.05693	$0.09193
44	GSLD	14.13%	1.40%	15.53%	1,874,791	0.03109	0.03111	0.05693	$0.08804
45	OL, OL1	0.43%	0.09%	0.52%	62,775	0.01588	0.01589	0.05693	$0.07282
46	SL1, SL2 & SL3	0.13%	0.03%	0.16%	19,315	0.01691	0.01692	0.05693	$0.07385
47	TOTAL	92.29%	7.71%	100.00%	$12,072,062				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21)
					(19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	144,617,000	$0.09755	$14,107,388
49	RS	<= 1,000kWh/mo.	92,734,000	$0.09396	$8,713,508
50	RS	> 1,000 kWh/mo.	51,883,000	$0.10396	$5,393,880
51	RS	Total Sales	144,617,000		$14,107,388

TOU Rates

		(22)	(23)	(24)	(25)
	Rate Schedule	On Peak Rate Differential	Off Peak Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
52	RS	0.0840	(0.0390)	$0.17796	$0.05496
53	GS	0.0400	(0.0500)	$0.13191	$0.04191
54	GSD	0.0400	(0.0325)	$0.13193	$0.05943
55	GSLD	0.0600	(0.0300)	$0.14804	$0.05804
56	Interruptibl	(0.0150)	-	$0.07304	$0.08804

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD - **With Amendment 1, Demand Alloc. Rev**
JANUARY 2012 - DECEMBER 2012
#REF!

NORTHWEST FLORIDA DIVISION

Over-recovery of purchased power costs for the period January 2012 - December 2012. (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 2012; (Estimated)	$	(3,248)
Estimated kilowatt hour sales for the months of January 2013 - December 2013 as per estimate filed with the Commission.		331,407,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2013 - December 2013.		(0.00098)

Exhibit No.________________
DOCKET NO. _120001-EI
Florida Public Utilities Company
(CDY-5)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION - **With Amendment 1, Demand Alloc. Rev**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

LINE NO.		(a) 2013 JANUARY	(b) 2013 FEBRUARY	(c) 2013 MARCH	(d) 2013 APRIL	(e) 2013 MAY	(f) 2013 JUNE	(g) 2013 JULY	(h) 2013 AUGUST	(i) 2013 SEPTEMBER	(j) 2013 OCTOBER	(k) 2013 NOVEMBER	(l) 2013 DECEMBER	(m) 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	1,614,262	1,544,125	1,493,593	1,265,996	1,348,952	1,671,750	1,792,733	1,812,048	1,737,157	1,600,356	1,332,782	1,460,235	18,673,989	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,099,235	1,064,480	1,015,232	1,026,879	1,055,259	1,075,619	1,068,181	1,072,719	1,062,291	1,036,932	1,021,471	1,057,945	12,656,243	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)	2,713,497	2,608,605	2,508,825	2,292,875	2,404,211	2,747,369	2,860,914	2,884,767	2,799,448	2,637,288	2,354,253	2,518,180	31,330,232	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,050,472	1,015,815	966,638	978,602	1,006,866	1,026,776	1,019,169	1,023,680	1,013,357	988,189	973,101	1,009,397	12,072,062	6
7	TOTAL OTHER COST TO BE RECOVERED	1,663,025	1,592,790	1,542,187	1,314,273	1,397,345	1,720,593	1,841,745	1,861,087	1,786,091	1,649,099	1,381,152	1,508,783	19,258,170	7
7a	SYSTEM KWH SOLD (MWH)	28,094	26,874	25,995	22,036	23,479	29,094	32,140	32,868	31,410	28,929	24,092	26,396	331,407	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.9195	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.7005	5.73282	5.71595	5.81103	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)	5.91950	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.70050	5.73282	5.71595	5.81103	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	10
11	TRUE-UP (CENTS/KWH)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	11
12	TOTAL	5.79782	5.80520	5.81095	5.84253	5.82979	5.79223	5.60870	5.54063	5.56470	5.57882	5.61114	5.59427	5.68935	12
13	REVENUE TAX FACTOR 0.00072	0.00417	0.00418	0.00418	0.00421	0.00420	0.00417	0.00404	0.00399	0.00401	0.00402	0.00404	0.00403	0.00410	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	5.80199	5.80938	5.81513	5.84674	5.83399	5.79640	5.61274	5.54462	5.56871	5.58284	5.61518	5.59830	5.69345	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	5.802	5.809	5.815	5.847	5.834	5.796	5.613	5.545	5.569	5.583	5.615	5.598	5.693	15

EXHIBIT NO. ________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-5)

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER

(EXCLUSIVE OF ECONOMY ENERGY PURCHASES) - **with Amendment 1, Demand Alloc. Rev**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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	2013	GULF POWER COMPANY	RE	29,823,425			29,823,425	5.412732	9.078424	1,614,262
FEBRUARY	2013	GULF POWER COMPANY	RE	28,527,660			28,527,660	5.412729	9.123093	1,544,125
MARCH	2013	GULF POWER COMPANY	RE	27,594,076			27,594,076	5.412732	9.070153	1,493,593
APRIL	2013	GULF POWER COMPANY	RE	23,389,223			23,389,223	5.412732	9.777473	1,265,996
MAY	2013	GULF POWER COMPANY	RE	24,921,830			24,921,830	5.412732	9.622933	1,348,952
JUNE	2013	GULF POWER COMPANY	RE	30,885,524			30,885,524	5.412729	8.875903	1,671,750
JULY	2013	GULF POWER COMPANY	RE	33,120,681			33,120,681	5.412731	8.619732	1,792,733
AUGUST	2013	GULF POWER COMPANY	RE	33,477,525			33,477,525	5.412731	8.599103	1,812,048
SEPTEMBER	2013	GULF POWER COMPANY	RE	32,093,915			32,093,915	5.412730	8.703980	1,737,157
OCTOBER	2013	GULF POWER COMPANY	RE	29,566,500			29,566,500	5.412729	8.899555	1,600,356
NOVEMBER	2013	GULF POWER COMPANY	RE	24,623,100			24,623,100	5.412728	9.536789	1,332,782
DECEMBER	2013	GULF POWER COMPANY	RE	26,977,780			26,977,780	5.412730	9.312034	1,460,235
TOTAL				345,001,239	0	0	345,001,239	5.412731	9.060324	18,673,989

EXHIBIT NO. __________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-5)

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON - **with Amendment 1, Demand Alloc Rev**
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	9.40	9.40	9.40	9.40	9.40	9.40	9.40
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	93.96	93.96	93.96	93.96	93.96	93.96	93.96
GROSS RECEIPTS TAX	3.25	3.25	3.25	3.25	3.25	3.25	3.25
TOTAL REVENUES *** $	129.94	129.94	129.94	129.94	129.94	129.94	129.94

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	9.40	9.40	9.40	9.40	9.40	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	93.96	93.96	93.96	93.96	93.96	1,127.52
GROSS RECEIPTS TAX	3.25	3.25	3.25	3.25	3.25	39.00
TOTAL REVENUES *** $	129.94	129.94	129.94	129.94	129.94	1,559.28

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. ____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-5)
PAGE 6 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION - **without Amendment 1**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

SCHEDULE E1
PAGE 1 OF 2

NORTHWEST FLORIDA 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)	18,673,989		345,001	5.41273
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)	13,447,859		345,001	3.89792
10a	Demand Costs of Purchased Power	12,863,678	*		
10b	Transformation Energy & Customer Costs of Purchased Power	584,181	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	32,121,848		345,001	9.31065
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	32,121,848		345,001	9.31065
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)	32,121,848		345,001	9.31065
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,252	*	239	0.00671
23	T & D Losses	1,243,437	*	13,355	0.37520
24	SYSTEM MWH SALES	32,121,848		331,407	9.69257
25	Less Total Demand Cost Recovery	12,863,678	***		
26	Jurisdictional MWH Sales	19,258,170		331,407	5.81103
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	19,258,170		331,407	5.81103
28	Projected Unbilled Revenues	(400,000)		331,407	(0.12070)
29	TRUE-UP **	1,503,740		331,407	0.45374
30	TOTAL JURISDICTIONAL FUEL COST	20,361,910		331,407	6.14408
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.14850
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	20,376,570			6.149

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO.____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)
PAGE 1 OF 14

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER - **Without Amendment 1**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(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	144,617,000	57.313%	28,804.6	1.089	1.030	31,368.2	148,955,510	50.65%	43.65%
35	GS	30,599,000	63.216%	5,525.6	1.089	1.030	6,017.4	31,516,970	9.72%	9.23%
36	GSD	90,797,000	73.904%	14,024.9	1.089	1.030	15,273.1	93,520,910	24.66%	27.40%
37	GSLD	60,298,000	84.021%	8,192.4	1.089	1.030	8,921.5	62,106,940	14.40%	18.19%
38	OL, OL1	3,954,000	178.492%	252.9	1.089	1.030	275.4	4,072,620	0.44%	1.19%
39	SL1, SL2 & SL3	1,142,000	178.492%	73.0	1.089	1.030	79.5	1,176,260	0.13%	0.34%
40	TOTAL	331,407,000		56,873.4			61,935.1	341,349,210	100.00%	100.00%

		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		12/13 * (8)	1/13 * (9)	(10) + (11)	Tot. Col. 13 * (12	(13)/(1)	(14) * 1.00072		(15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	)emand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	46.74%	3.37%	50.11%	$6,445,989	0.04457	0.04460	0.06149	$0.10609
42	GS	8.97%	0.71%	9.68%	1,245,204	0.04069	0.04072	0.06149	$0.10221
43	GSD	22.76%	2.11%	24.87%	3,199,197	0.03523	0.03526	0.06149	$0.09675
44	GSLD	13.29%	1.40%	14.69%	1,889,674	0.03134	0.03136	0.06149	$0.09285
45	OL, OL1	0.41%	0.09%	0.50%	64,318	0.01627	0.01628	0.06149	$0.07777
46	SL1, SL2 & SL3	0.12%	0.03%	0.15%	19,296	0.01690	0.01691	0.06149	$0.07840
47	TOTAL	92.29%	7.71%	100.00%	$12,863,678				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21)
					(19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
48	RS	Sales	144,617,000	$0.10609	$15,342,418
49	RS	<= 1,000kWh/mo.	92,734,000	$0.10250	$9,505,456
50	RS	> 1,000 kWh/mo.	51,883,000	$0.11250	$5,836,961
51	RS	Total Sales	144,617,000		$15,342,418

TOU Rates

		(22)	(23)	(24)	(25)
	Rate Schedule	On Peak Rate Differential	Off Peak Rate Differential	Levelized Adj. On Peak	Levelized Adj. Off Peak
52	RS	0.0840	(0.0390)	$0.18650	$0.06350
53	GS	0.0400	(0.0500)	$0.14221	$0.05221
54	GSD	0.0400	(0.0325)	$0.13675	$0.06425
55	GSLD	0.0600	(0.0300)	$0.15285	$0.06285
56	Interruptibl	(0.0150)	-	$0.07785	$0.09285

(2) From Gulf Power Co. 2009 Load Research data results.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD - **Without Amendment 1**
JANUARY 2012 - DECEMBER 2012
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2012 - December 2012. (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 2012; (Estimated)	$	1,503,740
Estimated kilowatt hour sales for the months of January 2013 - December 2013 as per estimate filed with the Commission.		331,407,000
Cents per kilowatt hour necessary to collection under-recovered purchased power costs over the period January 2013 - December 2013.		0.45374

Exhibit No.__________________
DOCKET NO. _120001-EI
Florida Public Utilities Company
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION - **Without Amendment 1**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
LINE NO.		2013 JANUARY	2013 FEBRUARY	2013 MARCH	2013 APRIL	2013 MAY	2013 JUNE	2013 JULY	2013 AUGUST	2013 SEPTEMBER	2013 OCTOBER	2013 NOVEMBER	2013 DECEMBER	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	1,614,262	1,544,125	1,493,593	1,265,996	1,348,952	1,671,750	1,792,733	1,812,048	1,737,157	1,600,356	1,332,782	1,460,235	18,673,989	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,165,203	1,130,448	1,081,200	1,092,847	1,121,227	1,141,587	1,134,149	1,138,687	1,128,259	1,102,900	1,087,439	1,123,913	13,447,859	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)	2,779,465	2,674,573	2,574,793	2,358,843	2,470,179	2,813,337	2,926,882	2,950,735	2,865,416	2,703,256	2,420,221	2,584,148	32,121,848	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,116,440	1,081,783	1,032,606	1,044,570	1,072,834	1,092,744	1,085,137	1,089,648	1,079,325	1,054,157	1,039,069	1,075,365	12,863,678	6
7	TOTAL OTHER COST TO BE RECOVERED	1,663,025	1,592,790	1,542,187	1,314,273	1,397,345	1,720,593	1,841,745	1,861,087	1,786,091	1,649,099	1,381,152	1,508,783	19,258,170	7
7a	SYSTEM KWH SOLD (MWH)	28,094	26,874	25,995	22,036	23,479	29,094	32,140	32,868	31,410	28,929	24,092	26,396	331,407	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.9195	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.7005	5.73282	5.71595	5.81103	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)	5.91950	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.70050	5.73282	5.71595	5.81103	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	10
11	TRUE-UP (CENTS/KWH)	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	0.45374	11
12	TOTAL	6.25254	6.25992	6.26567	6.29725	6.28451	6.24695	6.06342	5.99535	6.01942	6.03354	6.06586	6.04899	6.14408	12
13	REVENUE TAX FACTOR 0.00072	0.00450	0.00451	0.00451	0.00453	0.00452	0.00450	0.00437	0.00432	0.00433	0.00434	0.00437	0.00436	0.00442	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	6.25704	6.26443	6.27018	6.30178	6.28903	6.25145	6.06779	5.99967	6.02375	6.03788	6.07023	6.05335	6.14850	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	6.257	6.264	6.270	6.302	6.289	6.251	6.068	6.000	6.024	6.038	6.070	6.053	6.149	15

EXHIBIT NO. ________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES) - **without Amendment 1**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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	2013	GULF POWER COMPANY	RE	29,823,425			29,823,425	5.412732	9.299619	1,614,262
FEBRUARY	2013	GULF POWER COMPANY	RE	28,527,660			28,527,660	5.412729	9.354335	1,544,125
MARCH	2013	GULF POWER COMPANY	RE	27,594,076			27,594,076	5.412732	9.309219	1,493,593
APRIL	2013	GULF POWER COMPANY	RE	23,389,223			23,389,223	5.412732	10.059518	1,265,996
MAY	2013	GULF POWER COMPANY	RE	24,921,830			24,921,830	5.412732	9.887633	1,348,952
JUNE	2013	GULF POWER COMPANY	RE	30,885,524			30,885,524	5.412729	9.089491	1,671,750
JULY	2013	GULF POWER COMPANY	RE	33,120,681			33,120,681	5.412731	8.818907	1,792,733
AUGUST	2013	GULF POWER COMPANY	RE	33,477,525			33,477,525	5.412731	8.796155	1,812,048
SEPTEMBER	2013	GULF POWER COMPANY	RE	32,093,915			32,093,915	5.412730	8.909527	1,737,157
OCTOBER	2013	GULF POWER COMPANY	RE	29,566,500			29,566,500	5.412729	9.122673	1,600,356
NOVEMBER	2013	GULF POWER COMPANY	RE	24,623,100			24,623,100	5.412728	9.804700	1,332,782
DECEMBER	2013	GULF POWER COMPANY	RE	26,977,780			26,977,780	5.412730	9.556561	1,460,235
TOTAL				345,001,239	0	0	345,001,239	5.412731	9.289777	18,673,989

EXHIBIT NO. ________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON - **without Amendment 1**

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	10.25	10.25	10.25	10.25	10.25	10.25	10.25
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	102.50	102.50	102.50	102.50	102.50	102.50	102.50
GROSS RECEIPTS TAX	3.47	3.47	3.47	3.47	3.47	3.47	3.47
TOTAL REVENUES *** $	138.70	138.70	138.70	138.70	138.70	138.70	138.70

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	10.25	10.25	10.25	10.25	10.25	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	102.50	102.50	102.50	102.50	102.50	1,230.00
GROSS RECEIPTS TAX	3.47	3.47	3.47	3.47	3.47	41.64
TOTAL REVENUES *** $	138.70	138.70	138.70	138.70	138.70	1,664.40

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. ____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)
PAGE 6 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

NORTHEAST FLORIDA DIVISION		(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)	15,234,865	349,424	4.35999
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)	19,325,396	349,424	5.53064
10a	Demand Costs of Purchased Power	12,867,536 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	6,457,860 *		
11	Energy Payments to Qualifying Facilities (E8a)	1,469,762	23,770	6.18326
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	36,030,023	373,194	9.65450
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	36,030,023	373,194	9.65450
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)	36,030,023	373,194	9.65450
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	43,156 *	447	0.01208
23	T & D Losses	1,508,419 *	15,624	0.42238
24	SYSTEM MWH SALES	36,030,023	357,123	10.08897
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	36,030,023	357,123	10.08897
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	36,030,023	357,123	10.08897
27a	GSLD1 MWH Sales		24,000	
27b	Other Classes MWH Sales		333,123	
27c	GSLD1 CP KW		456,000 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	(255,610)	357,123	-0.07157
30	TOTAL JURISDICTIONAL FUEL COST	35,774,413	357,123	10.01739
30a	Demand Purchased Power Costs (Line 10a)	12,867,536 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	23,162,487 *		
30c	True up Over/Under Recovery (Line 29)	(255,610) *		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

NORTHEAST FLORIDA DIVISION		(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	12,867,536		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	1,563,169	456,000 (KW)	$3.43 /KW
33	Balance to Other Classes	11,304,367	333,123	3.39345
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	23,162,487		
35	Total KWH Purchased (Line 12)		373,194	
36	Average Cost per KWH Purchased			6.20655
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			6.39714
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,535,313	24,000	6.39714
39	Balance to Other Classes	21,627,174	333,123	6.49225
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,563,169	456,000 (KW)	$3.43 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$3.43 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,535,313	24,000	6.39714
40e	Total Non-demand Costs Including True-up	1,535,313	24,000	6.39714
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			6.40175
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	32,931,541	333,123	9.88570
41b	Less: Total Demand Cost Recovery	11,304,367 ***		
41c	Total Other Costs to be Recovered	21,627,174	333,123	6.49225
41d	Other Classes' Portion of True-up (Line 30c)	(255,610)	333,123	-0.07673
41e	Total Demand & Non-demand Costs Including True-up	21,371,564	333,123	6.41552
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	21,386,952		6.420

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

EXHIBIT NO. ___________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

NORTHEAST FLORIDA DIVISION

	Rate Schedule	(1) KWH Sales	(2) 12 CP Load Factor	(3) (1)/((2)*8,760) CP KW At Meter	(4) Demand Loss Factor	(5) Energy Loss Factor	(6) (3)*(4) CP KW At GEN.	(7) (1)*(5) KWH At GEN.	(8) (6)/Total Col. (6) 12 CP Demand Percentage	(9) (7)/Total Col. (7) Energy Percentage
44	RS	189,516,000	57.599%	37,560.1	1.089	1.030	40,902.9	195,201,480	64.48%	56.89%
45	GS	29,082,000	75.719%	4,384.5	1.089	1.030	4,774.7	29,954,460	7.53%	8.73%
46	GSD	86,323,000	78.538%	12,547.1	1.089	1.030	13,663.8	88,912,690	21.54%	25.91%
47	GSLD	25,652,000	77.959%	3,756.2	1.089	1.030	4,090.5	26,421,560	6.45%	7.70%
48	OL	1,416,000	4996.200%	3.2	1.089	1.030	3.5	1,458,480	0.01%	0.43%
49	SL	1,134,000	4996.200%	2.6	1.089	1.030	2.8	1,168,020	0.00%	0.34%
	TOTAL	333,123,000		58,253.7			63,438.2	343,116,690	100.01%	100.00%

	Rate Schedule	(10) 12/13 * (8) 12/13 Of 12 CP	(11) 1/13 * (9) 1/13 Of Energy	(12) (10) + (11) Demand Allocation Percentage	(13) Tot. Col. 13 * (9) Demand Dollars	(14) (13)/(1) Demand Cost Recovery	(15) (14) * 1.00072 Demand Cost Recovery Adj for Taxes	(16) Other Charges	(17) (15) + (16) Levelized Adjustment
50	RS	59.52%	4.38%	63.90%	$7,223,490	0.03812	0.03815	0.06420	0.10235
51	GS	6.95%	0.67%	7.62%	861,393	0.02962	0.02964	0.06420	0.09384
52	GSD	19.88%	1.99%	21.87%	2,472,265	0.02864	0.02866	0.06420	0.09286
53	GSLD	5.95%	0.59%	6.54%	739,306	0.02882	0.02884	0.06420	0.09304
54	OL	0.01%	0.03%	0.04%	4,522	0.00319	0.00319	0.06420	0.06739
55	SL	0.00%	0.03%	0.03%	3,391	0.00299	0.00299	0.06420	0.06719
	TOTAL	92.31%	7.69%	100.00%	$11,304,367				

Step Rate Allocation for Residential Customers

	Rate Schedule	(18) Allocation	(19) Annual kWh	(20) Levelized Adj.	(21) (19) * (20) Revenues
48	RS	Sales	189,516,000	$0.10235	$19,396,963
49	RS	<= 1,000kWh/mo.	119,001,000	$0.09863	$11,736,974
50	RS	> 1,000 kWh/mo.	70,515,000	$0.10863	$7,659,988
51	RS	Total Sales	189,516,000		$19,396,963

(2) From Florida Power & Light Co. 2010 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2012 - DECEMBER 2012
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Over-recovery of purchased power costs for the period January 2011 - December 2011. (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 2011.)(Estimated)	$	(255,610)
Estimated kilowatt hour sales for the months of January 2012-December 2012 as per estimate filed with the Commission. (Excludes GSLD1 customers)		333,123,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2012 - December 2012		-0.07673

FLORIDA PUBLIC UTILITIES COMPANY

NORTHEAST FLORIDA DIVISION

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

LINE NO.			(a)	(b)	(c)	(d)	(e)	(f)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	LINE NO.
								ESTIMATED								
			JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL PERIOD	
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		1,158,297	1,187,177	1,134,286	1,019,911	1,087,812	1,352,787	1,667,301	1,601,237	1,518,587	1,352,012	1,098,323	1,057,135	15,234,865	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,711,651	1,743,692	1,381,372	1,395,187	1,503,724	1,746,691	1,871,457	1,857,850	1,712,923	1,549,598	1,333,551	1,517,700	19,325,396	3a
3b	QUALIFYING FACILITIES		128,399	85,625	128,399	125,435	132,498	125,435	125,435	125,435	125,435	125,435	120,622	121,609	1,469,762	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,998,347	3,016,494	2,644,057	2,540,533	2,724,034	3,224,913	3,664,193	3,584,522	3,356,945	3,027,045	2,552,496	2,696,444	36,030,023	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,085,164	1,106,322	763,934	820,849	903,798	1,046,914	1,053,160	1,064,448	950,666	850,113	729,665	929,335	11,304,367	5a
5b	TOTAL OTHER COST TO BE RECOVERED		1,913,183	1,910,172	1,880,123	1,719,684	1,820,236	2,177,999	2,611,033	2,520,074	2,406,279	2,176,932	1,822,831	1,767,109	24,725,656	5b
6	APPORTIONMENT TO GSLD1 CLASS		258,387	258,026	258,474	259,208	258,965	257,987	257,259	257,389	257,568	257,989	258,494	258,736	3,098,482	6
6a	BALANCE TO OTHER CLASSES		1,654,797	1,652,146	1,621,649	1,460,476	1,561,271	1,920,012	2,353,774	2,262,685	2,148,711	1,918,943	1,564,337	1,508,373	21,627,174	6a
6b	SYSTEM KWH SOLD (MWH)		27,432	27,463	26,905	24,299	25,885	31,605	38,508	37,058	35,244	31,588	26,020	25,116	357,123	6b
7	GSLD1 MWH SOLD		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	7
7a	BALANCE MWH SOLD OTHER CLASSES		25,432	25,463	24,905	22,299	23,885	29,605	36,508	35,058	33,244	29,588	24,020	23,116	333,123	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.50675	6.48842	6.51134	6.54951	6.53662	6.48543	6.44728	6.45412	6.46346	6.48554	6.51264	6.52523	6.49225	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)		6.50675	6.48842	6.51134	6.54951	6.53662	6.48543	6.44728	6.45412	6.46346	6.48554	6.51264	6.52523	6.49225	9
10	GPIF ** (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	(255,610)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	(0.07673)	11
12	TOTAL		6.43002	6.41169	6.43461	6.47278	6.45989	6.40870	6.37055	6.37739	6.38673	6.40881	6.43591	6.44850	6.41552	12
13	REVENUE TAX FACTOR	0.00072	0.00463	0.00462	0.00463	0.00466	0.00465	0.00461	0.00459	0.00459	0.00460	0.00461	0.00463	0.00464	0.00462	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		6.43465	6.41631	6.43924	6.47744	6.46454	6.41331	6.37514	6.38198	6.39133	6.41342	6.44054	6.45314	6.42014	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.435	6.416	6.439	6.477	6.465	6.413	6.375	6.382	6.391	6.413	6.441	6.453	6.420	15

EXHIBIT NO. ________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

(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	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,566,440			26,566,440	4.360001	11.110977	1,158,297
FEBRUARY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	27,228,835			27,228,835	4.359999	10.907327	1,187,177
MARCH	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,015,725			26,015,725	4.360001	9.984350	1,134,286
APRIL	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	23,392,455			23,392,455	4.360000	10.661459	1,019,911
MAY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,949,825			24,949,825	4.359999	10.731450	1,087,812
JUNE	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,027,225			31,027,225	4.360000	10.243768	1,352,787
JULY	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,240,860			38,240,860	4.359999	9.460135	1,667,301
AUGUST	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,725,610			36,725,610	4.360001	9.633512	1,601,237
SEPTEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,829,980			34,829,980	4.360000	9.504424	1,518,587
OCTOBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,009,460			31,009,460	4.359999	9.611548	1,352,012
NOVEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	25,190,900			25,190,900	4.359999	9.947799	1,098,323
DECEMBER	2013	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,246,220			24,246,220	4.359999	10.929077	1,057,135
TOTAL				349,423,535	0	0	349,423,535	4.360000	10.151391	15,234,865

EXHIBIT NO. _________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

(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	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.114238	6.114238	128,399
FEBRUARY	2013	ROCK TENN & RAYONIER		1,470,000			1,470,000	5.824830	5.824830	85,625
MARCH	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.114238	6.114238	128,399
APRIL	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
MAY	2013	ROCK TENN & RAYONIER		2,100,000			2,100,000	6.309429	6.309429	132,498
JUNE	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
JULY	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
AUGUST	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
SEPTEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
OCTOBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.271750	6.271750	125,435
NOVEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.031100	6.031100	120,622
DECEMBER	2013	ROCK TENN & RAYONIER		2,000,000			2,000,000	6.080450	6.080450	121,609
TOTAL				23,770,000	0	0	23,770,000	6.183265	6.183265	1,469,762

EXHIBIT NO. ________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	9.86	9.86	9.86	9.86	9.86	9.86	9.86
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	98.63	98.63	98.63	98.63	98.63	98.63	98.63
GROSS RECEIPTS TAX	3.37	3.37	3.37	3.37	3.37	3.37	3.37
TOTAL REVENUES *** $	134.73	134.73	134.73	134.73	134.73	134.73	134.73

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	9.86	9.86	9.86	9.86	9.86	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	98.63	98.63	98.63	98.63	98.63	1,183.56
GROSS RECEIPTS TAX	3.37	3.37	3.37	3.37	3.37	40.44
TOTAL REVENUES *** $	134.73	134.73	134.73	134.73	134.73	1,616.76

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _________
DOCKET NO. 120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-6)

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION - **with Amendment 1**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA 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)	18,673,989		345,001	5.41273
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)	12,656,243		345,001	3.66847
10a	Demand Costs of Purchased Power	12,072,062	*		
10b	Transformation Energy & Customer Costs of Purchased Power	584,181	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,330,232		345,001	9.08120
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,330,232		345,001	9.08120
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)	31,330,232		345,001	9.08120
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	21,704	*	239	0.00655
23	T & D Losses	1,212,794	*	13,355	0.36595
24	SYSTEM MWH SALES	31,330,232		331,407	9.45370
25	Less Total Demand Cost Recovery	12,072,062	***		
26	Jurisdictional MWH Sales	19,258,170		331,407	5.81103
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	19,258,170		331,407	5.81103
28	Projected Unbilled Revenues	(400,000)		331,407	(0.12070)
29	TRUE-UP **	(3,248)		331,407	(0.00098)
30	TOTAL JURISDICTIONAL FUEL COST	18,854,922		331,407	5.68936
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				5.69346
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	18,868,497			5.693

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO.____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-7)
PAGE 1 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER - **With Amendment 1**
ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

NORTHWEST FLORIDA DIVISION

	Rate Schedule	(1) KWH Sales	(2) 12 CP Load Factor	(3) (1)/((2)*8,760) CP KW At Meter	(4) Demand Loss Factor	(5) Energy Loss Factor	(6) (3)*(4) CP KW At GEN.	(7) (1)*(5) KWH At GEN.	(8) (6)/Total Col. (6) 12 CP Demand Percentage	(9) (7)/Total Col. (7) Energy Percentage
34	RS	144,617,000	57.313%	28,804.6	1.089	1.030	31,368.2	148,955,510	50.65%	43.65%
35	GS	30,599,000	63.216%	5,525.6	1.089	1.030	6,017.4	31,516,970	9.72%	9.23%
36	GSD	90,797,000	73.904%	14,024.9	1.089	1.030	15,273.1	93,520,910	24.66%	27.40%
37	GSLD	60,298,000	84.021%	8,192.4	1.089	1.030	8,921.5	62,106,940	14.40%	18.19%
38	OL, OL1	3,954,000	178.492%	252.9	1.089	1.030	275.4	4,072,620	0.44%	1.19%
39	SL1, SL2 & SL3	1,142,000	178.492%	73.0	1.089	1.030	79.5	1,176,260	0.13%	0.34%
40	TOTAL	331,407,000		56,873.4			61,935.1	341,349,210	100.00%	100.00%

	Rate Schedule	(10) 12/13 * (8) 12/13 Of 12 CP	(11) 1/13 * (9) 1/13 Of Energy	(12) (10) + (11) Demand Allocation Percentage	(13) Tot. Col. 13 * (12) Demand Dollars	(14) (13)/(1) Demand Cost Recovery	(15) (14) * 1.00072 Demand Cost Recovery Adj for Taxes	(16) Other Charges	(17) (15) + (16) Levelized Adjustment
41	RS	46.74%	3.37%	50.11%	$6,049,310	0.04183	0.04186	0.05693	$0.09879
42	GS	8.97%	0.71%	9.68%	1,168,576	0.03819	0.03822	0.05693	$0.09515
43	GSD	22.76%	2.11%	24.87%	3,002,322	0.03307	0.03309	0.05693	$0.09002
44	GSLD	13.29%	1.40%	14.69%	1,773,386	0.02941	0.02943	0.05693	$0.08636
45	OL, OL1	0.41%	0.09%	0.50%	60,360	0.01527	0.01528	0.05693	$0.07221
46	SL1, SL2 & SL3	0.12%	0.03%	0.15%	18,108	0.01586	0.01587	0.05693	$0.07280
47	TOTAL	92.29%	7.71%	100.00%	$12,072,062				

Step Rate Allocation for Residential Customers

	Rate Schedule	(18) Allocation	(19) Annual kWh	(20) Levelized Adj.	(21) (19) * (20) Revenues
48	RS	Sales	144,617,000	$0.09879	$14,286,713
49	RS	<= 1,000kWh/mo.	92,734,000	$0.09520	$8,828,498
50	RS	> 1,000 kWh/mo.	51,883,000	$0.10520	$5,458,215
51	RS	Total Sales	144,617,000		$14,286,713

TOU Rates

	Rate Schedule	(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levelized Adj. Off Peak
52	RS	0.0840	(0.0390)	$0.17920	$0.05620
53	GS	0.0400	(0.0500)	$0.13515	$0.04515
54	GSD	0.0400	(0.0325)	$0.13002	$0.05752
55	GSLD	0.0600	(0.0300)	$0.14636	$0.05636
56	Interruptibl	(0.0150)	-	$0.07136	$0.08636

(2) From Gulf Power Co. 2009 Load Research data results.

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD - **With Amendment 1**
JANUARY 2012 - DECEMBER 2012
#REF!

NORTHWEST FLORIDA DIVISION

Over-recovery of purchased power costs for the period January 2012 - December 2012. (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 2012; (Estimated)	$	(3,248)
Estimated kilowatt hour sales for the months of January 2013 - December 2013 as per estimate filed with the Commission.		331,407,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2013 - December 2013.		(0.00098)

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION - **With Amendment 1**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

LINE NO.		(a) 2013 JANUARY	(b) 2013 FEBRUARY	(c) 2013 MARCH	(d) 2013 APRIL	(e) 2013 MAY	(f) 2013 JUNE	(g) 2013 JULY	(h) 2013 AUGUST	(i) 2013 SEPTEMBER	(j) 2013 OCTOBER	(k) 2013 NOVEMBER	(l) 2013 DECEMBER	(m) 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	1,614,262	1,544,125	1,493,593	1,265,996	1,348,952	1,671,750	1,792,733	1,812,048	1,737,157	1,600,356	1,332,782	1,460,235	18,673,989	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,099,235	1,064,480	1,015,232	1,026,879	1,055,259	1,075,619	1,068,181	1,072,719	1,062,291	1,036,932	1,021,471	1,057,945	12,656,243	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)	2,713,497	2,608,605	2,508,825	2,292,875	2,404,211	2,747,369	2,860,914	2,884,767	2,799,448	2,637,288	2,354,253	2,518,180	31,330,232	5
6	LESS: TOTAL DEMAND COST RECOVERY	1,050,472	1,015,815	966,638	978,602	1,006,866	1,026,776	1,019,169	1,023,680	1,013,357	988,189	973,101	1,009,397	12,072,062	6
7	TOTAL OTHER COST TO BE RECOVERED	1,663,025	1,592,790	1,542,187	1,314,273	1,397,345	1,720,593	1,841,745	1,861,087	1,786,091	1,649,099	1,381,152	1,508,783	19,258,170	7
7a	SYSTEM KWH SOLD (MWH)	28,094	26,874	25,995	22,036	23,479	29,094	32,140	32,868	31,410	28,929	24,092	26,396	331,407	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.9195	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.7005	5.73282	5.71595	5.81103	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)	5.91950	5.92688	5.93263	5.96421	5.95147	5.91391	5.73038	5.66231	5.68638	5.70050	5.73282	5.71595	5.81103	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	(0.12070)	10
11	TRUE-UP (CENTS/KWH)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	(0.00098)	11
12	TOTAL	5.79782	5.80520	5.81095	5.84253	5.82979	5.79223	5.60870	5.54063	5.56470	5.57882	5.61114	5.59427	5.68935	12
13	REVENUE TAX FACTOR 0.00072	0.00417	0.00418	0.00418	0.00421	0.00420	0.00417	0.00404	0.00399	0.00401	0.00402	0.00404	0.00403	0.00410	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	5.80199	5.80938	5.81513	5.84674	5.83399	5.79640	5.61274	5.54462	5.56871	5.58284	5.61518	5.59830	5.69345	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	5.802	5.809	5.815	5.847	5.834	5.796	5.613	5.545	5.569	5.583	5.615	5.598	5.693	15

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES) - **with Amendment 1**

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
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	2013	GULF POWER COMPANY	RE	29,823,425			29,823,425	5.412732	9.078424	1,614,262
FEBRUARY	2013	GULF POWER COMPANY	RE	28,527,660			28,527,660	5.412729	9.123093	1,544,125
MARCH	2013	GULF POWER COMPANY	RE	27,594,076			27,594,076	5.412732	9.070153	1,493,593
APRIL	2013	GULF POWER COMPANY	RE	23,389,223			23,389,223	5.412732	9.777473	1,265,996
MAY	2013	GULF POWER COMPANY	RE	24,921,830			24,921,830	5.412732	9.622933	1,348,952
JUNE	2013	GULF POWER COMPANY	RE	30,885,524			30,885,524	5.412729	8.875903	1,671,750
JULY	2013	GULF POWER COMPANY	RE	33,120,681			33,120,681	5.412731	8.619732	1,792,733
AUGUST	2013	GULF POWER COMPANY	RE	33,477,525			33,477,525	5.412731	8.599103	1,812,048
SEPTEMBER	2013	GULF POWER COMPANY	RE	32,093,915			32,093,915	5.412730	8.703980	1,737,157
OCTOBER	2013	GULF POWER COMPANY	RE	29,566,500			29,566,500	5.412729	8.899555	1,600,356
NOVEMBER	2013	GULF POWER COMPANY	RE	24,623,100			24,623,100	5.412728	9.536789	1,332,782
DECEMBER	2013	GULF POWER COMPANY	RE	26,977,780			26,977,780	5.412730	9.312034	1,460,235
TOTAL				345,001,239	0	0	345,001,239	5.412731	9.060324	18,673,989

EXHIBIT NO. _________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-7)

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON - **with Amendment 1**

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

	JANUARY 2013	FEBRUARY 2013	MARCH 2013	APRIL 2013	MAY 2013	JUNE 2013	JULY 2013
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	32.73	32.73
FUEL RECOVERY FACTOR CENTS/KWH	9.52	9.52	9.52	9.52	9.52	9.52	9.52
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	95.20	95.20	95.20	95.20	95.20	95.20	95.20
GROSS RECEIPTS TAX	3.28	3.28	3.28	3.28	3.28	3.28	3.28
TOTAL REVENUES *** $	131.21	131.21	131.21	131.21	131.21	131.21	131.21

	AUGUST 2013	SEPTEMBER 2013	OCTOBER 2013	NOVEMBER 2013	DECEMBER 2013	PERIOD TOTAL
BASE RATE REVENUES ** $	32.73	32.73	32.73	32.73	32.73	392.76
FUEL RECOVERY FACTOR CENTS/KWH	9.52	9.52	9.52	9.52	9.52	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	95.20	95.20	95.20	95.20	95.20	1,142.40
GROSS RECEIPTS TAX	3.28	3.28	3.28	3.28	3.28	39.36
TOTAL REVENUES *** $	131.21	131.21	131.21	131.21	131.21	1,574.52

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.150
	32.73

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. ____________
DOCKET NO. _120001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-7)