FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS

April 28, 2014

FLORIDA PUBLIC
UTILITIES

DOCKET NO. 140025-EI VOLUME III

FLORIDA PUBLIC UTILITIES COMPANY

INDEX
OF
TESTIMONY AND EXHIBITS

REDACTED

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS
OF
JEFFRY M. HOUSEHOLDER

Q. Please state your name, affiliation, and business address.

A. My name is Jeffry M. Householder. I am the President of Florida Public Utilities Company ("FPU" or "the Company"). My business address is 911 South 8th Street, Fernandina Beach, Florida 32034.

Q. Please summarize your professional experience and academic background.

A. I joined FPU in June 2010 in my current position. For ten years prior to joining FPU, I provided energy, regulatory affairs, and business development consulting services to natural gas utilities, natural gas marketing companies, propane gas retailers, government agencies, and industrial and commercial clients. In that capacity, I participated in numerous regulatory filings before the Florida Public Service Commission (Commission), including several rate proceedings. Prior to beginning my consulting business, I spent sixteen years in the gas and electric industry in the following positions: Vice President of Marketing and Sales for TECO Peoples Gas; Vice President of Regulatory Affairs and Gas Management for West Florida Natural Gas Company; Vice President of Marketing and Sales at City Gas Company; and Utility Administrative Officer for the City of Tallahassee Utilities. Early in my career, I was a Section Manager with the Florida Department of Community Affairs, responsible for administering the Florida Energy Code and related construction industry regulatory standards. I was also employed as an Energy Analyst in the Florida Governor's Energy Office. I received a Bachelor of Science Degree from Florida State University in 1978 with an interdisciplinary major in

Social Science (principally Economics and Business), and additional majors in Government and International Relations.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. Over the years, I have filed testimony in numerous cases. For example, I filed testimony most recently in Chesapeake Utilities' 2009 rate case proceeding (Docket No. 090125-GU). I also filed testimony on Chesapeake's behalf in the company's 2000 rate case (Docket No. 000108-GU). In 2007, I filed testimony on behalf of both Sebring Gas System and St. Joe Natural Gas Company in the Conservation Cost Recovery Clause proceedings (Docket No. 070004-GU). I also submitted testimony on behalf of Sebring Gas System in its 2004 rate case (Docket No. 040270-GU) and on behalf of St. Joe Natural Gas Company in its 2000 rate case (Docket No. 001447-GU). I have participated in quite a few other cases before the Commission either through the filing of testimony or development of programs, tariffs, or cost studies submitted for Commission review.

Q. Are you sponsoring any Exhibits to your Testimony?

A. Yes. I am sponsoring one exhibit, JMH-1, which is a year-by-year comparison of a residential bill for a residential typical 1,000 kWh customer on each of FPU's electric division systems since FPU's last rate case.

Q. Are you familiar with the operations and management of FPU's electric distribution utility?

A. Yes. As President of the Company, I am responsible for the overall management and direction of the electric utility and take an active role in strategic planning and resource allocation. I am also engaged in project development and regulatory issues on a regular basis.

Q. What is the purpose of your testimony in this proceeding?

A. My primary purpose is to provide an overview of current FPU operations, describe the current state of our company, address the impact that the acquisition by Chesapeake Utilities Corporation has had on FPU and introduce the witnesses in this case. I will also highlight some unique aspects of our case, as well the critical factors that have necessitated our filing. We have delayed filing for a rate increase as long as possible, but have reached the point where further delay is not in the best interests of the Company's customers or its shareholders. We take seriously our obligations to provide reliable and responsive service to our customers and the rates we seek support the continuation of that service obligation. I will outline our efforts to control costs while at the same time implementing several initiatives to significantly improve system reliability and the services we offer our customers.

Q. Please provide an overview of the Company.

A. This year, Florida Public Utilities Company will celebrate its 90th year of operations. In late 2009, FPUC merged with Chesapeake Utilities Corporation (Chesapeake), headquartered in Dover, Delaware. Chesapeake has operated in Florida since the late 1980's, when it acquired Central Florida Gas Company and Plant City Gas. At present, Chesapeake's principal Florida operations include regulated electric and natural gas distribution utilities, an intrastate gas transmission company, a natural gas marketing company and a propane distribution company. FPU is organized as a wholly owned subsidiary of Chesapeake.

FPU provides electric distribution service in two discrete Florida geographic areas – several small communities and rural areas in Jackson, Calhoun and Liberty counties (FPU's Northwest Division); and on Amelia Island (FPU's Northeast Division). The service areas present distinct service and growth challenges. While growth has been limited throughout both service areas, the counties in our Northwest Division have experienced an especially difficult time during the recent economic downturn. According to US Census data, Jackson and Liberty county populations have declined over the past several years, while Calhoun saw a minimal .04% increase. The City of Fernandina Beach on Amelia Island grew 1.9% since 2010. Construction activity has been at a virtual standstill in both Divisions although there are some signs of limited improvement on Amelia Island, where the first new residential subdivision (40 homes) in several years is breaking ground. FPU has experienced a declining usage trend over the past several years, not unlike many electric utilities in the U.S., as consumers conserve during tight economic times. Both FPU Divisions are subject to storm damage and outages. The Northeast Division operations also are susceptible to higher than typical levels of corrosion damage given the coastal location and a greater percentage of underground service. FPU's electric operation is also unique among Florida regulated electric utilities in that it does not own generation assets and, therefore, relies entirely upon wholesale power purchases to serve its 31,087 customers.

Q. How has the merger with Chesapeake impacted FPU?

A. The merger has resulted in several substantive benefits for customers, employees and the communities we serve. FPU's inclusion into a larger corporate structure provides greater access to lower cost capital. As other witnesses will detail, this capital has been carefully deployed to replace and upgrade old and failing electric infrastructure and equipment, increase storm hardening investments and generally return the Company's distribution infrastructure to a reliable operating condition. In addition, a more sophisticated management approach to the business is evidenced through the formal and disciplined planning, budgeting, project review and performance measurement processes introduced by Chesapeake. Significantly expanded resources are also now available to FPU in the areas of system planning and development, IT, HR, Treasury and risk management, communications and accounting.

Q. Can you provide examples of Chesapeake's resources and management influence benefiting customers, employees and communities?

A. Yes. Let me start with the employees. While our customers are central to every action we take, in Chesapeake's view the best way to take care of customers is to make sure employees are treated fairly and are fully engaged in the business. There is overwhelming evidence in numerous management and business studies that satisfied employees are directly correlated to satisfied customers. Over the four years of Chesapeake's management, a number of employee related actions have been taken. We first addressed the basics – conducting market based competitive pay reviews, bringing benefit packages up to industry standards and improving physical work conditions through equipment replacement and facility upgrades. In the Northeast Division, for example, we were operating out of a 100-year-old warehouse without operable indoor plumbing. Earlier this year we moved our employees into a modern office warehouse facility – with bathrooms. We also instituted a company-wide performance based pay system. The system sets performance standards for each employee along with Florida and corporate based annual financial, safety and customer satisfaction standards. Each employee's annual merit pay increase opportunity is directly tied to individual performance. In addition, a portion of each employee's target compensation (including our union employees represented by a collective bargaining unit) is based on achievement of the annual financial, safety and customer satisfaction performance targets. Finally, our employees are heavily engaged in the planning and review processes that fundamentally run our business. We communicate expansively at all levels in the Company to ensure that all employees understand our goals and performance standards.

Q. How have the employee initiatives benefitted customers and communities?

A. One of the fundamental elements of Chesapeake's business philosophy is that it lives by a set of key values. Striving to conduct business in an "Honorable" manner, making a "Personal Connection" with customers and communities and "Relentlessly" working to find new and better solutions to support customer needs are among these values. Building on the Values, a Service Excellence process is in place to continuously review and improve service to customers. Service Excellence teams map our processes, critically review our systems, and evaluate our contact methods through the "lens of the customer". Through this effort, we have instituted four primary Service Standards to guide our customer contact processes by which we measure success.

The most important of these Service Standards is "Safety". We want each of our employees to go home every night to their families in the same condition as they started the day. Equally important to us is the safety of our customers. We believe that our investments in system reliability, storm hardening, increased training programs and upgraded equipment discussed by witnesses Shelley and Cutshaw play a major role in keeping our customers and community's safe.

Our next Service Standard is "WOW". We want to give our customers the opportunity to be impressed by our efforts every time they come in contact with FPU employees. Through a series of employee training and empowerment actions, process improvements, technology upgrades and performance measurement activities we have vastly increased customer satisfaction. One measure is the number of Commission received customer complaints. In 2008, there were 37 complaints received by the Commission; in 2013 there were 4. In addition, we actively survey customers to assess our performance. Among other measurement metrics, we calculate a monthly and annual Net Promoter Score – essentially quantifying how many customers would recommend FPU to friends or neighbors. Our scores have steadily improved over the past two years to a very solid overall level. We continue to seek opportunities to keep improving. Another important example of this Service Standard is our willingness to play an active role in supporting the communities we serve. FPU employees are involved in numerous local service and civic organizations, charitable events, local sports sponsorships, business groups and trade associations.

Our third Service Standard is "Presentation". We adopted this standard after studying the Disney Company service standards. It applies not only to keeping our workplaces, vehicles and uniforms presentable (and safe), but also to presenting customers, vendors and service partners with straight-forward and useful methods to contact us and transact business. To this end, we have redesigned web sites, expanded payment options, extended Contact Center hours, modified CSR authority levels to support one call issue resolution, conducted a variety of community forums to provide information and promote energy conservation and other programs, improved our building parking, entry and customer service facilities for bill inquiries and payment, and numerous other customer-centric improvements.

Our final standard is "Results Oriented". We want every action we take, every decision we make and every activity in which we participate to have a positive result. I have touched on a few of the results we are achieving in the above discussion. The other witnesses in the case will provide additional indications that our Results Orientation is making a difference for our customers.

Q. Is the Company planning to take steps to further improve its service to customers?

A. Yes. One of the key initiatives when I was hired was a move to engage customers and glean an understanding of what they expected from us as a utility and further as a community partner. We have devoted significant resources to talking directly to customers, surveying customers, setting up e-mail response capabilities and working through various social media to develop that understanding. Those activities continue today as part of our on-going effort to see through the "lens of the customer". As a result we have restructure policies and procedures, streamlined organizational structures and improved technology. This year, we implemented a new Outage Management System in conjunction with a new GIS/mapping system.

We are working to link the systems to FPU Contact Centers and provide better information to customer service personnel. Ultimately, we will have an automated system for customers to both report an outage and receive information about an outage. Other witnesses in this case will outline several additional customer service improvements on the horizon. New telephony equipment, better capabilities to enable customers to self-serve (mobile apps, enhanced website payment plans, Kiosk payment centers) and an improved voice response system to reduce call wait times are in the works. Of course, we continue to work on operational service reliability as our primary customer service initiative. As we present our case, FPU witnesses will describe many of the physical system improvements we have completed and the excellent reliability results achieved to date.

Q. Please provide an overview of FPU's case and the testimony that will be presented by the Company's witnesses.

A. The Company's case will be presented by several FPU and Chesapeake corporate witnesses as well as outside experts retained to address certain aspects of the filing. These witnesses will collectively demonstrate the Company's focus on providing safe, reliable and high quality service to customers and its decreased ability to do so under the Company's current financial condition. Our witnesses will provide detailed information showing that our costs are reasonable and prudent and are being incurred at a level that exceeds our revenues. We will further demonstrate that both our actual and projected returns are well below the current authorized level and any level where the Company could reasonably expect to attract capital and continue to provide quality service to customers. Finally, our witnesses will provide a rate design that appropriately allocates our cost to provide service and establishes customer rates that are just and reasonable.

Several Company witnesses will describe FPU's efforts to improve service to customers. Drane A. "Buddy" Shelley, Director of Electric Operations and Mark Cutshaw, Director of Business Planning and Engineering will, collectively, submit panel testimony that outlines the significant investments in reliability and facility improvements since the last rate filing and planned through the test year. Their panel testimony also addresses various operational budget issues, along with the Company's recent historic and future planned efforts to reduce wholesale electricity purchase costs. Mariana "Guilly" Perea, Chesapeake Director of Customer Care, will discuss the Company's commitment to becoming an industry-recognized customer service operation. Ms. Perea also provides an overview of the focused effort we have made to improve our customer service operations and the performance results to date. Aleida Socarras, FPU Director of Marketing and Sales, describes the proposed economic incentive program, including the tariff rate provisions we are filing.

Several FPU, Chesapeake corporate and outside experts will present testimony on the Company's financial condition and proposed rate relief. Robert Canfield, Vice President of Christensen and Associates, will describe the forecast methodologies used to develop the FPU billing determinants and inflation factor. Cheryl Martin, FPU's Director of Regulatory Affairs, will address the overall need for rate relief and sponsor the principal financial information that supports the proposed revenue requirement increase. Ms. Martin is specifically responsible for the information provided in the Minimum Filing Requirements (MFR) Schedules A, B, C, D, F and G. Matt Kim, Chesapeake's Vice President and Corporate Controller will describe the Company's capital structure, related cost of capital, income tax expense and various corporate cost allocations. Mr. Kim also provides supporting testimony for several related financial MFR schedules. Paul Moul, will discuss the Company's cost of common equity. Finally, Company witness Mark Cutshaw will describe the Company's Cost of Service analysis and rate design within the panel testimony offered by he and Buddy Shelley.

Q. What is the specific rate relief that FPU is requesting in its filing?

A. FPU is requesting a permanent increase in its electric rates and charges in the amount of $5,852,171. This increase equates to an overall 6.79% increase in total revenues.

Q. Is FPU requesting interim rate relief?

A. Yes. FPU also seeks an interim increase in its electric rates and charges in the amount of $2,433,314 based on deficiency in revenues for the historic year ended September 30, 2013.

Q. Why is it imperative that FPU receive rate relief at this time?

A. Simply stated, the rates approved in the Company's 2008 rate case are no longer adequate to support the costs to provide quality service to customers. The Company has made significant investments in the infrastructure improvements, equipment and facilities and maintenance necessary to operate a safe, reliable electric system. We have also invested in improvements to our Customer Care operation, upgraded our system planning capabilities and ensured that our employee compensation and benefits are competitive. We have made these improvements in the face of flat to declining customer usage and revenues, because we feel a strong obligation to meet the service and reliability expectations of our customers. The costs of providing service have continued to increase over the seven-year interim since the Company's last rate case while revenues have not kept pace. The resulting negative impact on our electric financial returns has been predictable. In spite of the cost savings measures FPU has implemented, we have now reached the point where, without rate relief, we will be forced to delay important future capital investments and reduce maintenance actions that are critical to system reliability and efficiency.

Q. What are some of the actions the Company has taken to control costs and defer the need for this rate case?

A. As other witnesses describe in greater detail, FPU has taken several steps to control costs. We have implemented a number of process and organizational modifications that have enable us to continue to provide safe, reliable service without adding additional operational positions in either Division. We restructured our union agreements to make it easier for employees to cross division lines and now frequently share internal resources between divisions. As a result we are able to provide better service and reduce overtime and outside contractor costs. Last year, we established a System Planning and Engineering Unit that provides services to all Florida operations (electric, natural gas and propane). As examples, large project engineering and permitting and administration of the GIS/mapping system used by electric and natural gas operations are handled by the System Planning Unit. As a result, we have been able to share costs and reduce expenses. We have also had success in reducing maintenance costs through our investments to increase reliability. The replacement of old, high maintenance equipment has greatly improved our reliability metrics and reduced maintenance requirements. In spite of these efforts, however, the Company's costs continue to rise and further efforts to reduce costs would likely be detrimental to the Company's service quality and reliability performance.

Cost management alone is not enough to return the system to a sound financial footing. The return on equity has dropped each year since the prior rate case in 2008. Since 2010 it has been dramatically below the bottom of the Commission authorized range. The "Great Recession" stopped growth in our service areas, consumers appropriately reacted to the economy as well as the increasing electric wholesale prices by conserving, our operating costs continued to increase, and FPU invested heavily in system improvements following the Chesapeake acquisition. We have delayed seeking rate relief as long as possible; however, we no longer have that option.

Q. What is FPU's projected return on equity for the test year if relief is not granted?

A. The projected return on equity for the test year if relief is not granted will be a negative 1.46% in the year ending September 30, 2015. The projected overall rate of return is expected to be 1.27% for this same period. A rate of return at this low level is not in the best interest of the Company's customers. We will clearly be well below the 11.25% cost of common equity demonstrated as reasonable for FPU by Mr. Moul, to say nothing of the expectations of the Company's shareholders who provide the capital required to support system integrity and service to our customers.

Q. You describe above the impact of the recent economic turndown. Does FPU play a role in the economic recovery and development of the communities you serve?

A. I believe we have an important role to play. We work closely with economic development teams in each of the areas we serve. It is clear that the ability to provide reliable, competitively priced electricity is one of the fundamental concerns of both individuals and corporations evaluating sites for residence or development. From a business perspective, economic growth brings additional customers and revenue. It also promotes the more efficient use of existing distribution resources. Ultimately, growth helps spread costs and minimize future rate increase pressures. Aleida Socarras will testify to FPU's current level of economic development support and describe our interest in expanding support for local and regional development efforts. We have watched with admiration the economic development actions of other Florida utilities in close proximity to our service areas (Gulf Power and Florida Power and Light). While our resources are more limited, it is appropriate that we support both regional and local efforts to grow the economies of the areas we serve.

In this filing, we are seeking approval of an Economic Development Rider. Ms. Socarras will provide greater detail on the Rider. It is our intent to promote additional economic development and job growth through certain rate discounts offered to businesses either relocating or expanding in FPU's service areas.

Q. FPU's request includes testimony that suggests that fuel rate relief for customers may be expected in the near term. Please explain.

A. As witnesses Cheryl Martin and Mark Cutshaw will explain in more detail in their testimony, the Company is very conscious of the economic environment within which we are making this request for an increase. While the revenue increase is paramount to our ability to continue to provide safe, reliable service to our customers, we do recognize that any rate increase can result in a hardship to customers. Over the past several years, we have diligently pursued other avenues by which we might achieve overall bill savings for customers. The most critical focus has been on reducing the cost of wholesale purchased power. FPU's base rates are among the lowest for Florida utilities. Our wholesale power costs have, however, been among the highest over the past five years. We have made significant progress in that area by negotiating an amendment to our existing purchase power agreement with Gulf Power and by entering into an agreement to purchase renewable power from the Rayonier Performance Fibers QF cogeneration plant on Amelia Island. We also make periodic as available power purchases from the Rock Tenn QF cogeneration plant also on Amelia Island. Each of these actions has produced significant savings for our customers. Other options are under consideration.

It is FPU's intent to file in May 2014 a proposed purchase power agreement to acquire power from Eight Flags Energy, LLC, a Chesapeake affiliate. Eight Flags is in the final stage of developing [redacted] The FERC certified QF would sell [redacted] The power purchases are anticipated to be significantly lower than FPU's current wholesale power purchase pricing. In addition, the [redacted]

[redacted] would enable [redacted] and purchase the additional power. [redacted]. The Eight Flags project is scheduled to be in-service in Q1 2016.

At present, FPU's base rates are consolidated, but the fuel rates are individually approved for each division. In the Commission's 2014 fuel docket, FPU will seek Commission approval to consolidate its fuel cost recovery across both FPU operating divisions, consistent with the Commission's direction in the 2013 Fuel and Purchased Power Cost Recovery docket. Such a consolidation will ensure that all FPU customers participate in the fuel cost reduction described above. As Mr. Cutshaw describes in his testimony, the [redacted] the base rate increase requested in this filing.

Given that the savings are not scheduled to begin until 2016, FPU will be seeking options, in its Fuel and Purchased Power Cost Recovery filing, to mitigate some of the base rate increase in 2015. Our intent is to reduce consumer fuel costs by deferring collection of a portion of our fuel costs until the 2016 savings are realized. An action of this type would allow the Company to recover the revenue requirement authorized by the Commission, while smoothing out any rate increase as much as possible.

Q. Does this conclude your direct testimony?
A. Yes.

FLORIDA PUBLIC UTILITIES COMPANY
Year By Year Comparison Of Electric Residential Bill (1,000 kwh customer)
Period Of 2009 - Current (Proposed Rates)
DOCKET NO.: 140025-EI

NORTHEAST RESIDENTIAL TYPICAL BILL FOR 1,000 KWH'S

Residential (RS)	2009	2010	2011	2012	2013	2014	Proposed
Customer Charge	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$16.00
Base Rate Energy Charges ($/KWH)	$0.01958	$0.01958	$0.01958	$0.01958	$0.01958	$0.01958	$0.02170
Base Rate Demand Charges ($/KW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Purchased Power Cost Recovery Clause ($/KWH)	$0.09438	$0.09615	$0.09630	$0.09311	$0.09786	$0.08975	$0.08975
Energy Conservation Cost Recovery Clause ($/KWH)	$0.00078	$0.00080	$0.00115	$0.00115	$0.00155	$0.00100	$0.00100
Gross Reciepts Tax	$3.25	$3.30	$3.31	$3.23	$3.36	$3.14	$3.29
Total Monthly Bill	**$129.99**	**$131.83**	**$132.34**	**$129.07**	**$134.35**	**$125.47**	**$131.74**
Base Revenue % Increase		0.0%	0.0%	0.0%	0.0%	0.0%	19.4%
Total % Increase		1.4%	0.4%	-2.5%	4.1%	-6.6%	5.0%
Units	1,000	1,000	1,000	1,000	1,000	1,000	1,000

NORTHWEST RESIDENTIAL TYPICAL BILL FOR 1,000 KWH'S

Residential (RS)	2009	2010	2011	2012	2013	2014	Proposed
Customer Charge	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$16.00
Base Rate Energy Charges ($/KWH)	$0.01958	$0.01958	$0.01958	$0.01958	$0.01958	$0.01958	$0.02170
Base Rate Demand Charges ($/KW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Purchased Power Cost Recovery Clause ($/KWH)	$0.10093	$0.11927	$0.10136	$0.09854	$0.09883	$0.09740	$0.09740
Energy Conservation Cost Recovery Clause ($/KWH)	$0.00078	$0.00080	$0.00115	$0.00115	$0.00155	$0.00100	$0.00100
Gross Reciepts Tax	$3.42	$3.89	$3.44	$3.37	$3.38	$3.33	$3.49
Total Monthly Bill	**$136.71**	**$155.54**	**$137.53**	**$134.64**	**$135.34**	**$133.31**	**$139.59**
Base Revenue % Increase		0.0%	0.0%	0.0%	0.0%	0.0%	19.4%
Total % Increase		13.8%	-11.6%	-2.1%	0.5%	-1.5%	4.7%
Units	1,000	1,000	1,000	1,000	1,000	1,000	1,000

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FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS
OF
CHERYL M. MARTIN

Q. Please state your name, affiliation, business address, and summarize your academic background and professional experience.

A. My name is Cheryl Martin. I am the Director of Regulatory Affairs for Florida Public Utilities Company (FPU) including the Florida Division of Chesapeake Utilities (Central Florida Gas or CFG), Peninsula Pipeline, and Eight Flags Energy, LLC (Eight Flags). FPU has its administrative offices at 1641 Worthington Road, Suite 220, West Palm Beach, Florida 33409. I have been employed by FPU since 1985 and performed numerous accounting functions until I was promoted to Corporate Accounting Manager in 1995 with responsibilities for managing the Corporate Accounting Department including regulatory accounting (fuel, PGA, conservation, rate cases, surveillance reports, reporting), tax accounting, external reports, and special projects. In January 2002, I was promoted to the position of Controller where my responsibilities included those above with additional responsibilities in the purchasing and general accounting areas and Security and Exchange Commission (SEC) filings. I was promoted to my current position in August 2011. My current responsibilities include directing the regulatory affairs for the Company in Florida including regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC) for FPU, FPU-Indiantown, FPU-Fort Meade, Central Florida Gas, and Peninsula Pipeline Company. I graduated from Florida State University in 1984 with a B.S. in Accounting. I am also a Certified Public Accountant in Florida.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes, on several occasions. Among the dockets in which I have participated most recently, I testified in the Company's 2007 rate case in Docket No. 070304-EI, as well as the 2003 rate case in Docket No. 030438-EI, the 1993 rate case in Docket No. 930400-EI, and our 1988 rate case in Docket No. 881056-EI. I also provided testimony in the 2008 rate case for our Natural Gas Division in Docket No. 080366-GU, as well as the 2004 Natural Gas rate case in Docket No. 040216-GU and the 1990 and 1994 rate cases, addressed in Dockets Nos. 900151-GU, and 940620-GU, respectively. I have also filed testimony on numerous occasions in the Fuel and Purchased Power Cost Recovery proceeding, as well as in the Conservation Cost Recovery clause dockets and the annual Purchased Gas Adjustment proceedings. In addition, I have also been involved in the development of other regulatory filings in Florida on behalf of FPU and other Chesapeake companies.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. A summary of those exhibits follows:

Exhibit CMM-1 provides a list of the MFRs that were prepared under my supervision and direction.

Exhibit CMM-2 provides the detail for the account and amortization of the Regulatory Asset-Pensions.

Exhibit CMM-3 provides the detail for the account and amortization of the Regulatory Asset - Litigation Costs/Gulf Refund.

Exhibit CMM-4 provides the detail for the account and amortization of the Regulatory Asset -Tax Step Up (A new regulatory asset requested in this proceeding).

Exhibit CMM-5 provides the detail for the account and amortization of the Regulatory Liability –Tax Gain.

Exhibit CMM-6 provides the detail for the account and amortization of the Regulatory Liability – Post Retirement Benefit.

Exhibit CMM-7 provides the detail for the account and amortization of the Regulatory Asset – General Liability Claim and the related General Liability Reserve (A new regulatory asset and reserve being requested in this proceeding).

Exhibit CMM-8 provides the Company's current and former Paid Time Off Policies.

Q. Are you sponsoring any MFRs in this case?

A. Yes. I am sponsoring the MFRs listed in Exhibit CMM-1. I have reviewed and support the analysis and schedules listed in this exhibit. To the best of my knowledge, these MFRs are true and correct.

Q. What is the purpose of your testimony in this proceeding?

A. I am providing the financial information that supports the proposed increase in revenue requirements for FPU, electric operations. I am specifically responsible for the information provided in the Minimum Filing Requirements (MFR) Schedules A, B, C, D, F and G, as indicated in Exhibit CMM-1. Supporting information and additional testimony for these schedules has also been provided by the Corporate Office of Chesapeake Utilities Corporation (CUC) under the direction of the Corporate Vice President, Matt Kim, as well as the Director of Electric Operations, Drane A. "Buddy" Shelley, and Director of Business

Planning and Engineering, Mark Cutshaw. The President of Florida Public Utilities Company, Jeffry Householder, has also included testimony in support of this proceeding. The Company's Director of Sales and Marketing, Aleida Socarras, our Director of Customer Care, Mariana "Guilly" Perea and our Cost of Capital and Billing Determinant experts, Paul Moul, and Robert Camfield, respectively, have likewise provided information that I have utilized in the development of these schedules. With regard to the MFR E Schedules, Mark Cutshaw is specifically responsible for the information provided therein.

Q. Why is FPU seeking a rate increase in its base rates at this time?

A. The last rate increase proceeding was initiated seven years ago and was based on a 2006 historic year and 2008 forecasted test year. Since that time, the Company has been acquired by Chesapeake Utilities Corporation, a transaction consummated in 2009. Prior to the merger, the Company did not have adequate capital resources to make necessary reliability improvements to the electric systems or facilities in its service territories. In stark contrast, as a new subsidiary of Chesapeake, the Company has undertaken significant reliability improvements to its electric system, and capital expenditures have increased since the last rate proceeding. Also as a result of the merger, the Company has experienced decreases in certain expenditures since its last rate proceeding due to specific measures taken by the Company to consolidate functions within the electric operations. Some of these costs savings measures have been offset by increases in costs including expanded safety measures, increased communication to our employees and customers, and enhanced customer care initiatives. Our projections indicate that we can expect many costs to continue to increase; and for the most part, these costs are beyond our control. The Company is committed to providing customers, reliable service and superior customer service, while also ensuring our employees are adequately trained, operate in a safe environment, and are adequately compensated with competitive pay and benefits. Another contributing factor is the inflationary impacts on new and replacement utility plant, as well as operating expenses. Cost increases continue to contribute to the declining rate of return. The Company believes the proposed September 2015 test year will accurately reflect the economic conditions in which the consolidated electric division will be operating during the first twelve months the new rates will be in effect, and as such, this period is appropriate for rate setting purposes. The Company has not been able to achieve its allowed rate of return in the last 3 years. It has therefore become necessary for the Company to seek a rate increase at this time to allow the Company the opportunity to earn a fair rate of return on its investment in utility plant and working capital. Earning a fair rate of return will enable the Company to continue providing a high quality of service and to maintain its financial integrity, which are in the best interest of its customers.

Revenue Requirement

Q. What is the revenue increase requested by FPU in this proceeding?

A. FPU is requesting a permanent increase in the electric rates and charges for its consolidated electric operations in the amount of $5,852,171 in order to cover the deficiencies in revenue for the projected test year ending September 30, 2015. In accordance with Rule 25-6.140, F.A.C., Test Year Notification, we have notified the FPSC that we have selected the twelve month period ending September 30, 2015 as the projected test year for our petition to increase our rates and charges. FPU is also requesting an interim increase in the electric rates and charges for its consolidated operations in the amount of $2,433,314 based on deficiency in revenues for the historic year ended September 30, 2013.

Q. How did you derive the projected revenue requirement for the September 30, 2015 test year?

A. The derivation of the revenue requirement and projected revenue deficiency is summarized on MFR Schedule A-1. In summary, the 2015 revenue requirement is determined by multiplying the projected test year rate base by the required rate of return to arrive at the operating income required. This required operating income is then compared to the projected year ended September 30, 2015 operating income, shown on MFR Schedule C-1 using our existing billing rates and charges and projected rate base and operating expenses. Any deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required to realize a fair rate of return on rate base. This required increase amounts to an additional $5,852,171 in annual electric rates and charges. The required rate of return is 7.18% as shown on Schedule D-1a. The projected rate base is $60,596,169 and is provided in MFR Schedule B-1.

Interim Revenue Requirement

Q. You are also requesting that the Commission grant interim relief. Why are you seeking Interim Rate Relief at this time?

A. FPU is seeking Interim Rate Relief because as of September 30, 2013 the

Company is not earning a sufficient return on its investment to allow shareholders the opportunity to earn a fair rate of return. Capital investments, including reliability improvements, have increased without significant offsetting customer growth. Expenses have increased, and the current trends in the housing markets, appliance efficiency, and overall economy have presented further pressures that negatively impact our earnings. For several years, the Company has been, and is, currently below the low point of our allowable return. Without rate relief, the Company is expected to continue to earn a return well below its allowable rate of return. If that continues, this will jeopardize our ability to provide sufficient, consistent reliable service to our customers. With the length of the rate case process, interim rates will mitigate our negative earnings posture through the pendency of the rate case and until final rates can be put in place.

Q. How did you derive the interim revenue requirement?

A. The derivation of the revenue requirement for interim relief is summarized in MFR Schedule G-1. In summary, the interim revenue requirement is determined by multiplying the historic year ended September 30, 2013 rate base by the required rate of return using the last authorized rate of return (low-point authorized common equity rate) to arrive at the operating income required. This required operating income is then compared to the actual year ended September 30, 2013 operating income. Any deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required on an interim basis until final rates can be reviewed and authorized. The required rate of return for interim purposes is shown on MFR Schedule G-19a. The interim rate base for the historic year ended September 30, 2013 is shown on MFR Schedule G-2.

We have made the appropriate net operating income (NOI) adjustments in this filing to reflect the findings in the Company's last rate case, including elimination of fuel and conservation costs and revenues; elimination of shared facilities with non-regulated operations, and interest synchronization. We have removed any item that belonged in a prior period, or was out of period, as appropriate in the historic year net operating income schedules, and consistent with Commission practice. See explanations in the NOI section of this testimony for additional details on those adjustments.

We are asking therefore that the Commission allow us to collect appropriate interim rates pending the effective date of the final order in this proceeding. We recognize that, in accordance with Section 366.071, F.S., any approved interim increase will be subject to refund with interest upon the outcome of these proceedings. We therefore request that the Commission allow the Company to secure the requested amount through corporate undertaking, in lieu of a bond. FPU, through its parent Chesapeake, has sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund as reflected by our financial statements, which are incorporated in the MFR Schedules F-1 and F-2.

Rate Base

Q. What is the amount of rate base included in the projected test year September 30, 2015, as a basis for determination of revenue requirement?

A. As set forth in MFR Schedule B-1, Rate Base for the projected test year is \$60,596,169. The Rate Base is comprised of two main sections, Net Plant and Working Capital.

Q. What was the basis for projecting the Rate Base?

A. The Company did a detailed analysis and projection of capital projects, retirements, and other components for the projected years ending September 30, 2014, and September 30, 2015, to project Net Plant. The Company utilized experts in the division, including the Director of Electric Operations, Drane (Buddy) Shelley, and Director of Business Planning and Engineering, Mark Cutshaw, as well as input from other key employees to determine the projects, amounts and timing of items to be included in Net Plant projections. The Company has planned capital projects required by storm hardening, reliability, infrastructure replacement, and other key projects; all have been incorporated into these projections. Working Capital was projected using both trend factors applied to the historic year September 30, 2013 thirteen month average balances or year end balances as appropriate, and direct projections for certain balance sheet accounts that do not lend themselves to projections based on trend factors.

Q. What is the amount of FPUC's capital additions for the historic year ending September 30, 2013, and the capital budget for the two projected years

ending September 30, 2014 and 2015, respectively?

A. The capital additions for the twelve months ending September 2013 were \$6,936,887. The capital budget for periods ending September 30, 2014 and 2015 are \$6,706,924 and \$3,195,398 respectively.

Q. Please explain how the Capital Budget forecasts were developed for this rate proceeding?

A. For all utility plant accounts and construction work in progress (CWIP), actual account balances were used through February 2014. For the remainder of 2014 through September 2015, plant accounts were projected based on anticipated changes in timing, projects and amounts. The original internal 2014 FPUC capital budgets were developed during the latter half of the previous year, using detailed analysis of planned projects at the time of the budget development. Detailed analysis of this original plan was completed during the early part of 2014 by division directors and managers, and the capital forecasts were updated with known and planned changes.

Q. Why did the Company's Capital Budget forecast change from the internal budget used for financial reporting?

A. The budget that is currently used in financial reporting was prepared well before the rate proceeding was compiled. The Company used the internal budget forecasts for capital projections as a starting point for the forecast for this rate proceeding. It was updated with more timely information and expectations. A more thorough review of the capital projects was completed by key management personnel responsible for capital projects, including Drane "Buddy" Shelley and Mark Cutshaw. Their panel testimony includes more details regarding the projected capital projects for the two projected years reflected in this rate proceeding.

Q. Are the capital projects and related forecasts included in this rate proceeding the best estimate for what will be expected during the two projected years ending September 30, 2015?

A. Yes, the forecasts used in rate base for net plant are the most up to date estimates of what is expected and planned. The Company prepared detailed projections for expected projects and retirements, and the projections used in this rate proceeding reflect our best estimate for the plant that will be in service or under construction for the two projected years.

Q. Are the capital projects planned for the two projected years necessary?

A. Yes, as further explained in the panel testimony of our witnesses Mark Cutshaw and Buddy Shelley, the planned projects consist of replacing and/or upgrading aging/unreliable underground conductors, relay control schemes at substations, transmission circuit breakers, substation buss, wooden poles, distribution regulators/reclosures and the relocation of inaccessible distribution lines to roadways. The planned capital projects are necessary for system reliability, improvements and replacement.

Q. Is it appropriate to include the construction work in progress (CWIP) planned for the projected test year in rate base?

A. Yes, the Company should be allowed to earn a fair return on capital projects under construction. Costs associated with these projects are all prudently incurred and necessary, and therefore, should be included in rate base. Historically, the Commission has allowed construction work in progress to be included in rate base for FPU. These projects are not subject to the Allowance for Funds Used during Construction and accordingly, will not receive duplicate recovery on these projects while in construction. In its previous rate case in Docket 070304-EI, the Company had included, for full recovery in rate base, a transformer that was ordered during the historic year, 2006; but, it had not been delivered by December 2007. The Company proposed that, for the purposes of rate setting, it was appropriate that the full 13-month average remain in the 2008 average rate base and be allowed for recovery. The Company also received recovery for CWIP during the projected test year. The Commission agreed and accepted our proposal. If full recovery of CWIP had not been allowed, it would have accelerated the need for the Company to seek further rate relief sooner than otherwise necessary, thereby increasing the overall cost to the customers associated with rate case costs. With this filing, we also believe it is appropriate for the Commission to allow us to recover costs associated with ongoing construction; because, these projects are critical to maintaining and improving our system reliability and ability to meet our customers' needs.

Q. What was the basis for the trend factors used for certain working capital items?

A. MFR Schedule C-7 contains a listing of the projection factors used. The most commonly used trend factors include Inflation, Payroll Growth, Customer

Growth, and Inflation & Customer Growth. The payroll trend factor is based on historical data, the experience of the Company's Human Resources Director, and her best estimate of expected payroll increases for both 2014 and 2015. The factors for customer growth, unit (kWh) growth and revenues are based on detailed analysis and the results from revenue related projections used within this rate proceeding. The methodology used to determine the billing determinant and revenue factors as well as the inflation factors are explained in greater detail in the testimony of Robert Camfield.

Trend factors were used that were consistent with those used in expense projections and in our prior rate proceedings.

Q. How were the relative trend factors applied to working capital?

A. The Company reviewed each balance sheet item, and when appropriate utilized a trend factor applied to the thirteen month average balance when it was necessary to reflect fluctuations that occur due to payment timing and seasonality. Some accounts were trended using the balance that existed at year end, when those accounts do not fluctuate with payment timing and seasonality. This basis produced a better projection. The Company performed analysis of all working capital components; reviewed historical methodology used for these same components, reviewed expense items related to these components, and relied upon internal expertise to determine the most appropriate factor to project the working capital components. Customer growth was used in trending the balance sheet accounts where the transactions were directly or indirectly associated with billing determinants. Inflation was used to trend accounts directly impacted by anticipated cost of living increases. Payroll was used to trend all payroll related accounts. Some accounts utilized a combination of trend factors such as Account 1420-Accounts Receivable, when changes not only are impacted by customers, but also the inflationary impacts to costs.

Q. What items included in working capital were projected using a direct method and what is a summary of the basis for those projections?

A. Some working capital accounts were projected using a method outside of a pure trend. Several accounts were directly projected using historical data, known or expected changes, or separate detailed analysis. The details of these projections are summarized below:

Account 1240/1430-A/R Other Investments: The balance of this account does not typically fluctuate year to year or month to month and is not expected to change in the next two projected years. The historic year-end amount was used to project this account.

Account 1310-Cash: This account was projected using a combination of trend factor and direct estimate. Since this account is materially impacted by accounts receivables and fuel related purchases, the customer growth factor was applied to the historic September 2013 13-month average balance of Depository Cash to arrive at the projected 13-month average balances for September 2014 and September 2015, respectively. The individual months for the projected years were then trended based on the monthly balance fluctuations of the historic year to account for seasonality. Part of this account, Account 1312-General Disbursements – Cash, was forecast to remain at the normal level of outstanding checks to be funded by FPU's parent company, Chesapeake Utilities Corporation.

<u>Account 1350-Petty Cash:</u> The balance of this account does not historically fluctuate, nor is it expected to fluctuate in the two projected years. Accordingly, this account was projected to remain at $8,000 per month.

<u>Account 1430-Miscellaneous Accounts Receivable</u>: The monthly balance of this account does not typically fluctuate from year to year and is not expected to materially change in the two projected years. The historic amounts were used for the projection.

<u>Account 1730-Unbilled Revenues:</u> A detailed analysis and forecast of unbilled revenues was prepared by our witness Robert Camfield for the projected years. Management reviewed and supports this estimate, and accordingly, this was used to project the related working capital component.

<u>Account 1823-Other Regulatory Assets Pension and Other Post-Retirement Benefits (OPRB)</u>: The projected years were computed by using the actual monthly balances from October 2013 through February 2014. We then adjusted each subsequent month's balance by the monthly amortization of $23,064, authorized by the Florida Public Service Commission to commence in November 2009, and to continue through the remaining life of the asset. The Company

received authorization from the Commission by Order PSC-08-0134-PAA-PU to create a regulatory asset related to a valuation adjustment on pension and retiree medical expense in accordance with FASB 158 requirements that existed due to the merger between FPU and Chesapeake Utilities Corporation. Company witness Matt Kim provides additional details on the pension expense projection in his testimony. See Exhibit CMM-2 for details on the account and amortization amounts reflected in the MFR.

<u>Account 1823-Other Regulatory Assets Tax Step-up</u>: Since the merger, FPU's statutory rate increased to 35 percent. This increase in the federal statutory rate increased FPU's effective income tax rate to 38.575 percent from 37.63 percent. Since FPU had a net deferred tax liability associated with its plant assets at the time of the merger, this resulted in a deficiency in the deferred tax reserve. The South Georgia method is one of the methods of the tax normalization accounting, which allows utilities to amortize the deficiency over the remaining lives of the property that gave rise to the deficiency. The tax step-up currently in regulatory assets, including tax gross up is $248,666. See Exhibit CMM-4 for details on the amortization amounts reflected in the MFR.

<u>Account 1823-Other Regulatory Assets Deferred Litigation</u>: The Company requested deferral treatment for the NW litigation costs in 2012. The Commission granted the Company's request for this deferral by PSC Order No. 12-0600-PAA-EI and Order No. 13-0599-PAA-EI. This account reflects the actual amounts being amortized during the projected periods.

Specifically, in August 2012, FPU requested approval to establish a regulatory asset to defer the litigation expenses associated with ongoing litigation with the City of Marianna. The basis and reasons for that litigation are detailed in full in prior Commission Dockets Nos. 100459-EI, 110041-EI, 120227-EI, and 130233-EI. On November 5, 2012, the Commission approved our request and permitted the Company to amortize the accumulated litigation costs, $1,869,657, over a 5-year period beginning January 2013. In March 2013, FPU and the City of Marianna reached a settlement resolving the aforementioned litigation. With the litigation resolved, Gulf began charging the lower capacity payments based on the amendment to our purchased power agreement that was approved in Docket No. 110041-EI. Gulf also refunded to FPUC the difference between the higher capacity payments from the original agreement and the lower capacity payments set forth in the approved amendment.

On November 13, 2013, the Commission issued Order No. PSC-13-0599-PAA-EI, allowing FPUC to apply the refund of $1,766,624 to the regulatory asset and amortize the net remaining amount over the existing five year period. The Regulatory Asset – Litigation reflects the appropriate amount in accordance with the Commission Order. See Exhibit CMM-3 for the account and amortization amounts reflected in this rate proceeding.

<u>Account 1860-Deferred Rate Case:</u> The projection for this account was based on detailed estimates based on expected expenditures necessary to prepare this rate

proceeding. The total accumulated rate case expense was then amortized over five years. MFR Schedule C-10 and additional testimony contained within this document, includes more details on the rate case expense.

Account 228.1-Storm Reserve: The projected balance of this account was forecast to increase by monthly accruals of $10,135 over the historic year, and adjusted for estimated storm costs based on historical activity and inflationary impacts to expected costs. This amount is consistent with our prior rate proceedings, See Docket No. 070300-EI. Conditions related to storm activity has not materially changed from our last rate proceeding to warrant a change in the storm reserve at this time. The reserve, with current accruals, is sufficient to provide recovery for storm costs over the next five years.

Account 2282-Accrued Liability Insurance: This account was projected based on detailed analysis of historical activity, known claims, and to project the impacts from a requested general liability reserve. I will further address the requested General Liability expense and reserve in the NOI section of my testimony. Our witness Matt Kim also addresses details associated with this in his testimony. See Exhibit CMM-7 for the amortization reflected in this proceeding.

Account 2283-Accrued Pension & Post Retirement Medical, Account 2283-Accrued Pension & Post Retirement Medical Allocated and Account 2283-Accrued Retiree Fees, Claims & Contributions: These accounts were projected based on a detailed estimate provided by Matt Kim on expected Pension and Post retirement expenses. Matt Kim's testimony includes additional details surrounding the related expense accounts.

Account 2370-Interest Accrued: The Company currently accrues interest on its mortgage bond at $60,533 (allocated @ 24% to electric) per month and makes semiannual payments on the accumulated balance in May and November of each year. The Company projected the monthly balances in the test year to reflect this same historic year amount.

Account 2410-Tax Collections Payable: The balance of this account typically does not fluctuate from zero. Tax payments generally match monthly accruals. The Company appropriately projected this account to consistently maintain an expected zero balance.

Account 2420-Misc. Current & Accrued Liabilities: With very few exceptions, this account has maintained a zero balance throughout the historic year. The Company appropriately projected this account to consistently maintain an expected zero balance.

Account 2520-Customer Advances For Construction: This account contains contracts with customers with an expiration date. The forecast reflects the diminishing balance due to expected refunds at the contract expiration date, with no additional contracts projected.

Account 2540-Regulatory Liability: This account contains the actual amount of a deferred gain, and the associated amortized amount authorized by the Florida Public Service Commission in Order No. PSC-12-0574-PAA-PU, issued October 24, 2012. By that Order, FPU received approval to record a tax liability associated with vehicle depreciation as a regulatory liability and amortize that liability over a 34-month period beginning January 1, 2012, through October 31, 2014. See Exhibit CMM-5 for the account and amortization amounts reflected in this rate proceeding.

This account also contains an additional regulatory liability associated with a one-time gain FPU incurred due to a change made to the Company's Post-Retirement Benefits. The merger between FPU and CUC prompted a continued effort to conform the benefits offered to FPU's employees to those offered to CUC's employees. This change reduced FPU's obligation under the plan. By Commission Order No. PSC-13-0594-PAA-PU, FPU was allowed to recognize the one-time gain and amortize it also over the 34-month period beginning January 1, 2012 and ending October 31, 2014. See Exhibit CMM-6 for the account and the amortization amount reflected in this rate proceeding.

Q. Is working capital as projected appropriate for computing the projected test year rate base for the period ending September 30, 2015?

A. Yes, the working capital as projected is appropriate for inclusion into rate base for the period ending September 30, 2015. The Company performed analysis of working capital accounts, reviewed historical methodology used for these same components, and reviewed expense items related to these accounts to determine the most appropriate factor to use to project the working capital.

Q. Please elaborate with more information to understand what is included in Net Plant.

A. The Company has included costs of significant reliability improvements to the infrastructure of its electric operations made since the last rate proceeding or will be made during the projected test year and prior year. In addition, the Company was operating out of facilities in its Northeast (NE) division, which were not only inadequate in terms of space, but were also in need of substantial repairs. In particular, the warehouse was deteriorating and was not sufficient to allow the Company to properly serve our customers, as further discussed in the panel testimony of witnesses Cutshaw and Shelley. There was not sufficient space in the administrative building or the warehouse to sufficiently serve the customers in this area or provide employees with adequate working facilities. The Company therefore made a prudent decision to build a new facility, which included the warehouse complex. This facility was prudently constructed, is centrally located, allows for efficient communications between personnel, and is adequate to serve its customers. To be clear, the Company has removed the old warehouse from rate base for purposes of rate base determination.

The old administrative building located in the NE division is currently being used for Florida Common purposes, and associated costs are allocated among the Florida business units, because they share in the benefits of the Common services and functions. This building is allocated to the Florida business units based on the level of investment by Business Unit; electric receives 16.7% of this allocation. This percentage is a fair estimate for the benefit the electric utility receives from this facility, and as such, is allocated appropriately.

Details of these and specific larger projects embedded in the rate base projections have been included in the MFRs, as well as the testimony provided by witnesses Cutshaw and Shelley.

Q. What are the items that are included in net plant that have been allocated from Corporate to the Electric operating unit?

A. The eCIS plus is a corporate wide billing system project. This is an upgrade from the current billing system. eCIS plus is being allocated from the Company's Corporate CWIP to each business unit's CWIP, based on their respective number of customers. This project is expected to enhance the options available to customers as well as provide additional analysis to the Company. See Mariana Perea's testimony for more details regarding the improvements made to customer service including those anticipated in the near future.

Q. What are the items that are included in net plant that have been allocated from Florida Common to the Electric operating unit?

A. The Company determined that certain Plant Assets were categorized as Florida Common due to their shared utilizations between multiple regulated and/ or non-regulated utilities. These assets are detailed on Schedule B-8 under Common

Plant.

Q. What is the basis for the allocation from Common Plant to the Utility?

A. Many common plant accounts, with the exception of Computer Equipment and Software and the Florida Common office, were allocated based on the utility's share of non-Common, total consolidated plant (exclusive of Computer Equipment and Software). Common's Computer Equipment and Software accounts were allocated to the electric utility based on the utility's share of total consolidated customers. The Florida NE Common office was allocated based on net investments.

Q. How does the electric division benefit from these assets?

A. These assets are necessary to the electric division in the day-to-day operations of the utility, enabling the Company to effectively and efficiently function in a number of areas, ranging from internal communications to customer care to maintenance issues. They are essential to the electric division, and the overall Company, in the performance of its duties and service to its customers. Shared resources provide benefits to the electric customers through efficient utilization of assets.

Q. Please explain the item and nature for all adjustments included in rate base for the historic and projected years included in the MFR filing?

A. The Company has removed plant and its reserve for a portion of the assets used for non-utility operations, consistent with the treatment approved in Docket

070304-EI. The adjustment to net plant, for the historic test year, decreased rate base by $222,737. For the period ending September 30, 2014, rate base was decreased by $507,448, and for the period ending September 30, 2015, rate base was decreased by $407,936.

In our last rate case Order, Order PSC-08-0327-FOF-EI, the Commission eliminated fuel and conservation under-recoveries and employee receivables. An adjustment was made to rate base to remove the net under-recoveries, which were $227,971 in the historic year, $590,782 at September 30, 2014, and $250,042 for the projected year ending September 30, 2015. The projected amounts of fuel under and over recoveries were based on detailed analysis of the expected fuel cost recovery in the projected years.

In that same Order PSC-08-0327-FOF-EI, the Commission also eliminated Non-Utility (Employee) Receivables from working capital. Working capital was increased in the historic year because the employee receivable included in the actual 13-month average balance sheet at September 30, 2013 was a credit of $4,248.

The Commission likewise removed one-half of deferred rate case expenses. Consistent with the Commission's decision, we removed one-half of the projected deferred rate case expenses. The reduction to projected rate base was $148,077 in the September 30, 2014 test year and $346,028 in the September 30, 2015 test year. There was no adjustment necessary to the historic test year for this item since there was no rate case expense being amortized.

The historic test year included other adjustments to record amortization of regulatory assets and liabilities that were established by Commission Orders in 2012 and 2013. These adjustments were not necessary in the projected years because the assets and liabilities were forecast for the September 30, 2014 and 2015 years using the adjusted amounts. For instance, in the historic test year, a regulatory asset was established by Order No. PSC-12-0600-PAA-EI for recovery of litigation costs with the City of Marianna. The Commission later approved a settlement whereby the Company was allowed to substantially reduce that asset by the amount of proceeds of a refund from Gulf Power, as set forth in Order No. PSC-13-0599-PAA-EI. The 13-month average of the costs less the amount approved by the settlement and the approved amortization resulted in an average balance of $470,288. However, the actual net average balance recorded in working capital for this asset was $377,922. Therefore, an increase of $92,306 was made to rate base for 2013 to reflect the authorized amount and amortization in the Commission orders.

Commission Order PSC-13-0594-PAA-PU issued on November 4, 2013, established a regulatory liability for the one-time gain realized as a result of the change in its post retirement benefits and approved the Company to amortize the regulatory liability over a 34-month period beginning January 1, 2012 and ending October 31, 2014. For the thirteen month average as of September 30, 2013, the books reflected a balance of ($258,659). Based on this order, the balance should have been ($144,545). Therefore, rate base was increased by $114,114 for 2013 to reflect the Commission order.

The final adjustment was to properly reflect the regulatory liability - tax gain and related amortization established in Commission Order PSC-12-0574-PAA-PU. The 13-month average balance included in the historic test year working capital balance was ($416,777). The balances based on the Commission Order resulted in an average of ($519,927). Therefore, rate base was reduced by $103,150.

No other adjustments were made to rate base.

Revenues and Billing Determinants

Q. What was the method for determining the projected test year billing determinants?

A. The billing determinants and operating revenues have been projected using a test year ended September 30, 2015. To project operating revenues for 2015 the Company used current rates multiplied by the projected 2015 weather-normalized billing determinants (number of customers and usage). The Company also included the impact of the energy efficient appliances, economic conditions and projected base revenue increases on customer's consumption. Also, despite some customer growth in our Northeast (NE) division, the Northwest (NW) division continues to struggle with the economic downturn that the nation as a whole has endured over the last several years. The NW division is mostly rural, and does not have the same prospect for customer growth that our NE division anticipates; therefore, recovery has been slower. Robert Camfield further addresses this issue in his testimony. Additional information with regard to the billing determinant forecasts may also be found in Schedule F-5. Projected operating revenues for 2015 are shown on MFR Schedule C-5.

Q. Does the Company feel that the billing determinants and revenue forecast used in this MFR filing are appropriate for the two projected years?

A. Yes, the Company has reviewed the analysis, results and testimony provided by Robert Camfield. After careful consideration, FPU has concluded that the results are appropriate and fairly represent the revenues and billing determinants expected for the two projected years including the projected test year ending September 30, 2015.

<u>NOI and Operating Expenses</u>

Q. **Does the historic test year accurately reflect net operating income?**

A. Yes, the Company has included all adjustments to remove items that did not belong ("out of period") in the historic year, and accordingly the MFR Schedule C-1 for the period ending September 30, 2013 reflects the appropriate historic year net operating income. "Out of period" refers to adjustments on the Company's books in the historic year that belong in another period. Other adjustments were required to the historic year to remove items that do not belong to the electric divisions, or were required in past rate proceeding.

Q. Please explain the items and basis for any adjustments made to operating income for the historic year included in MFR Schedules C-2 and C-3.

A. Fuel and Conservation:

Consistent with the prior rate proceeding, the fuel and conservation revenues and expenses have been eliminated from both the historic and projected years. These items are handled in separate dockets outside of the base rate proceeding and are appropriate for review and approval within those separate proceedings.

Gross Receipts and Franchise tax:

Gross Receipts tax and Franchise tax revenue and expenses have also been eliminated from the historic and projected test years. Although they are not handled in separate dockets, it is appropriate to remove them. They are a direct pass-through for revenues and expenses and they are excluded from setting base rates.

Unbilled Revenues:

Unbilled revenues were decreased by $122,438 due to a correction made in December 2013 that impacted the period January 2012 through December 2013. The error involved the use of an improper input in the computation of unbilled revenues; but, the issue was subsequently corrected. This reduced amount reflects the portion of the adjustment made in December 2013 that belonged in the historic year ending September 30, 2013.

Marianna Litigation Expenses:

Adjustments were made to correct O&M and amortization expense associated with the Marianna litigation. This is relevant to litigation initiated on March 2, 2011, when the City of Marianna filed a complaint against FPU in the Circuit Court in Jackson County, Florida. Further details regarding this issue are also included in the panel testimony of witnesses Cutshaw and Shelley, as well as in the Commission Docket No. 100459-EI. In summary, the City of Marianna alleged that FPU breached its franchise agreement. The City of Marianna was seeking judgment allowing it to exercise its option under the franchise agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated, among other items, the City of Marianna proceeding with a referendum on the purchase of FPU's facilities within the City of Marianna. On April 19, 2013, the referendum took place, and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase of FPU's facilities by the City of Marianna. Total litigation expense associated with the City of Marianna was approximately $1,871,000. As previously noted in my testimony, In August 2012, the Company sought Commission approval to establish a regulatory asset to defer the litigation expenses associated with the ongoing litigation with the City of Marianna and amortize it over a five (5) year period beginning January 2013. Upon receiving approval for treatment as a regulatory asset and approval to offset these costs with the refund from Gulf Power Company, by Order No. PSC-12-0600-

PAA-EI and Order No. PSC-13-0599-PAA-EI, respectively, the Company reversed expenses from a prior period of $1,319,358 in the actual historic year ending September 30, 2013. Thus, the prior period expense reversal was eliminated from the historic year appropriately. Also, in January 2013, the Company began amortizing the regulatory asset pertaining to the Marianna litigation at $31,161 per month for a total of $280,449 in the historic year. Since the Commission allowed the refund from Gulf Power to offset the regulatory asset related to the Marianna litigation, the amortization should have been lower and recorded at just $15,455. The amortization expense was reduced by $264,994 to correct the historic year results to reflect the actual amortization authorized by the Commission. Exhibit CMM-3 details the regulatory asset and related amortization.

Pension and Post Retirement Benefit:

In December 2012, the Company adjusted on its books, pension and post-retirement benefit expense true-ups and cost capitalization for the years 2010 through 2012. Of these adjustments, only three months were relevant to the historic year, and the remaining months and years were adjusted out of this period. Adjustments to NOI are listed below:

Pension true-up and cost capitalization	$39,226
Post-retirement true-up	$76,134

Depreciation Expense:

The Company has removed depreciation expense of $10,768 for a portion of the assets used for non-utility operations from the historic year, which is also consistent with the treatment used in our 2007 rate case in Docket 070304-EI.

Transformer:

Expenses have been reduced by $46,610 for costs related to a transformer that should have been capitalized during the historic year period. This entry was subsequently corrected on the Company's books in December 2013.

Income Tax Gain:

Amortization expense has been adjusted to eliminate $246,285 for prior period amortization related to an income tax liability allocated to the electric operations. After an internal audit of FPU records, it was determined that an income tax liability that originated on the Company's books prior to its merger with Chesapeake Utilities Corporation was no longer collectable by the Internal Revenue Service. The tax liability related to depreciation on company vehicles and the tax liability had outlived the applicable statute of limitations set forth by IRS Code and as such was no longer deemed a tax-related liability, and therefore could be excluded from the deferred tax liability account. FPU sought and received approval from the Commission, by Order No. PSC-12-0574-PAA-PU, to record a tax liability associated with the vehicle depreciation as a regulatory liability and to amortize that liability over a thirty four-month period beginning January 2012 through October 2014. Upon approval by the Commission, the amortization gain true-up of this regulatory liability ($301,015) was recorded on the Company books in November 2012 for the period January 2012 – November 2012. However, only two months were relevant to the historic year, and the remaining months were adjusted out of this period.

Paid Time Off:

In 2013, Chesapeake Utilities Corporation also made a change to the Paid Time Off (PTO) Policy for employees in FPU to align them with the Company wide PTO policy. The old PTO policy that originated with FPU prior to the merger accumulated the subsequent years change in total vacation pay as a liability and expense. The policy, because of the way the liability was created, resulted in pre accrual of future vacation pay changes. If an employee left the company on January 1st of the current year, they were entitled to the entire current calendar year's PTO pay as a payout. Accordingly, GAAP required the Company to record any change in the overall future liability prior to the related actual PTO or the actual payout year. The change in pay or additional weeks was then booked as an additional liability in the year preceding the actual payout. The new policy requires employees to accrue PTO as they work during the calendar year. Now, whenever an employee leaves the Company, they are only entitled to a PTO payout for the amount of PTO they have accrued during the current calendar year. A one-time reversal of the total accumulated PTO liability on the books in the historic year period was booked in the 2013 calendar year. The accumulation of this liability occurred over the last several decades and as such, the one-time reversal that occurred during the historic year relates to prior period expenses and does not belong in the historic year. The historic year has been adjusted to eliminate the impact of this change for $141,687 on the electric division's books. My Exhibit CMM-8 sets forth the new and old PTO policies.

Post Retirement Benefits:

During 2012, CUC modified the benefits offered to its FPU employees under the post-retirement health and life plan. This caused a one-time gain on the Company's books. FPU sought permission from the Commission to establish a regulatory liability and amortize this liability over a thirty four month period beginning January 1, 2012 and ending October 31, 2014. In November 2013, the Commission approved this request by Order No. PSC-13-0594-PAA-PU. Since the authorized amortization was not reflected in the historic year, an adjustment of $91,291 was made to NOI so that the historic year accurately reflects this amortization.

Vehicle Depreciation:

The depreciation on vehicles was calculated at the incorrect rate for the historic year ending September 30, 2013. An adjustment was made to NOI for $41,739 for the difference in the actual calculation versus what was recorded on the Company's books for the historic year ending September 30, 2013. Because depreciation expense on vehicles is allocated to FERC accounts following the related payroll expense, this change is reflected in O&M instead of depreciation expense. This entry was subsequently corrected on the Company's books in March 2014.

PSC Assessment:

Taxes other than income (TOTI) expense for PSC Assessment was increased by, $2,120, to account for the difference between accruals and actual payments on the Company's books.

Adjustments - Income Tax Impact:

The effective income tax rate on the adjustments described above has been appropriately included as an additional adjustment to expense in the historic year ending September 30, 2013.

For reference, MFR Schedules C-2 and C-3 include a summary of these adjustments and amounts.

Q. **Have you calculated the appropriate adjustment in income taxes to reflect the synchronized interest expense related to the adjusted rate base?**

A. Yes. The NOI has been adjusted to reflect the tax effect of synchronizing interest expense to rate base. Consistent with prior Commission practice, the synchronized or calculated interest expense is computed by multiplying the jurisdictional adjusted rate base by the weighted cost of debt included in the cost of capital. This adjustment ensures that the calculated revenue requirement reflects the appropriate tax deduction for the interest component of the revenue requirement calculation.

Q. How did you project Operating and Maintenance (O&M) expenses for the projected test year ending September 30, 2015?

A. The expenses reflected in this filing were projected separately for the business unit and corporate costs allocated to the business unit.

O&M expenses for the corporate office of Chesapeake Utilities Corporation (CPK) allocated to the electric utility were projected by Matt Kim. Additional details regarding those projections and related allocations to the Business Unit are included in his testimony.

O&M expenses for the business unit were projected by the Florida office. Business unit expenses were projected using the historic year as a starting point, making all necessary adjustments as reflected in this rate proceeding for the historic year and either trending those forward with an appropriate trend factor, or directly projecting the expense using the expertise of internal managers or known items impacting certain expenses as a basis for the projection.

Final projected O&M amounts were reviewed by internal managers and analysts and were determined to be a good estimate for expected costs during the projected test year.

Q. **Please explain in more detail the basis for projecting the business unit expenses included in the MFR filing.**

A. The business unit O&M expenses for the historic year ending September 30, 2013, provide the basis for most of the business unit expense items in the projected test year ending September 30, 2015. Each FERC account was separated into its payroll and non-payroll components for the historic year. All historic adjustments were made to the payroll and non-payroll components to exclude "out of period" items or other items as reflected in the historic year adjustments described in this testimony and shown on MFR Schedule C-2.

Some historic year amounts were then adjusted to normalize the expenses for the purpose of trending historic year accounts to the projected years. Normalization adjustments only impacted the projected years' amounts and were not included for purposes of establishing the historic year expenses included in the NOI for the period ending September 30, 2013. To normalize, expenses were re-classified to their appropriate FERC account to reflect a more accurate expense projection by FERC. This was just a transfer between accounts and did not change the overall expense level.

Then the adjusted historic year expenses plus or minus the "normalization" amounts were multiplied by one of several trend factors. Trend factors have been applied that are appropriate for each account and consistent with prior rate proceedings.

Some historic year items that were trended did not reflect the annual amount expected; estimates have been adjusted for increases and decreases to the trended amounts (Over and Under), as shown on MFR Schedule C-7 page 9.

Some expense items have been projected based on direct cost estimates provided by our internal management. Examples of direct cost estimates would include: pension, general liability, economic development, rate case and tree trimming.

The application of trend factors, including over and under items plus the direct projections, produced reasonable and expected results in O&M amounts for the projected test year.

Q. Please explain the items and the basis for any normalization adjustments made to operating expenses for the purpose of trending O&M expenses for the projected test year?

A. Normalization adjustments were made to the historic year in order to arrive at the appropriate expense level by FERC account for projection purposes. We re-classed expenses recorded on the Company's books from corporate Administrative and General (A&G) to non-corporate/business unit Distribution and A&G to ensure they were properly classified and aligned by FERC. These adjustments had no impact to NOI. Below are descriptions of the normalization adjustments made to the historic year for purposes of trending projected year expenses:

- Payroll not classified to correct FERC-$351,834
- Electric General Managers payroll and other expenses-$102,398
- IT related costs-$54,567
- System Planning department-$34,350
- Facilities Expenses-$81,365
- Advertising expenses -$28,750

Q. Please explain the basis of the trend factors used to project O&M expenses for the projected test year.

A. MFR Schedule C-7 contains a listing of the projection factors used. The most commonly used trend factors include Inflation, Payroll Growth, Customer Growth, Inflation & Customer Growth, and Payroll Growth & Customer Growth. The payroll trend factor is based on historical data, the experience and expertise of the Company's Human Resources Director, and her best estimate of expected payroll increases for both 2014 and 2015. The factors for customer growth, unit (kWh) growth and revenues are based on detailed analysis and the results from revenue related projections used within this rate proceeding. The methodology used to determine the billing determinant and revenue factors as well as the inflation factors are explained in greater detail in the testimony of Robert Camfield.

Q. How did the Company determine the appropriate trend factor for each expense projection?

A. All expenses were divided into two components, payroll (if applicable) and non-payroll. The payroll expenses for each account used either the Payroll or Payroll and Customer growth trend factors. The payroll factor was used on payroll accounts, like 560-Supervision and Engineering and 920-A&G Salaries. All other payroll components used the Payroll and Customer growth factor because the Company expects payroll to increase by not only the expected rate of pay, but also the expected overall number of personnel, as more customers are added. Although it is not a direct correlation, personnel will fluctuate overall by the number of customers the Company serves. The non-payroll component was based on the type of expense and most appropriate trend factor for the account.

This is consistent with historically approved trend factors used in prior rate proceedings, and resulted in expected levels of expenses.

Q. Can you explain the basis for the projected expenses outside of those based on historical data trended to the projected test year?

A. Operation and Maintenance over and under adjustments, as well as direct projections, were made to certain accounts outside of trending historical data when management determined that a trend would not adequately reflect expected results. A detailed listing of the over and under adjustments as well as direct projections has been included in MFR Schedule C-7. The Company utilized internal experts to project certain expenses shown as Direct.

Q. Can you summarize the items that were projected on a Direct Basis?

A. The pension expense of $280,219 was projected by the corporate office of Chesapeake Utilities Corporation. All other employee benefit expenses were trended based on payroll and customer growth factor.

Corporate O&M expenses, including pension expense, are reflected as Direct and were projected by the corporate office of Chesapeake Utilities Corporation, which is further explained in the testimony of our witness Matt Kim.

The projected regulatory Commission expense (i.e., rate case expense) was based on specific forecasts from consultants, attorneys, and in-house review of appropriate, anticipated costs. FPU estimates the incremental expenses related to this rate case to be $770,721. The Company is requesting to recover these expenses at a rate of $154,144 per year over a five-year amortization period, which is consistent with the Commission's decision in previous FPU rate cases. NOI has been adjusted by $154,144 for the projected test year. Detailed specifics of these costs are explained later in this testimony and can be found on MFR Schedule C-10.

Depreciation & amortization expenses for the year ended September 30, 2015, are projected to be $3,704,295. The detailed projected plant and the applicable depreciation rates approved during the Company's last depreciation study per Order PSC-12-0065-PAA-EI were used as a basis for depreciation expense. Depreciation expense was adjusted for a portion of non-electric usage for the office structures in Fernandina Beach. The depreciation expenses are shown by plant sub-account on MFR Schedule B-9.

Amortization expense includes the remaining amortization of regulatory assets and liabilities approved by the Commission as well as those we are requesting within this rate proceeding; thus, amortization of the tax regulatory asset for the South Georgia-Tax Step Up (Federal tax rate change from 34% to 35%) and for the General Liability Claim are included. Matt Kim provides additional details on these new, requested regulatory tax assets in his testimony as well as additional details contained within this testimony. The amortization is listed below as well as on MFR Schedule C-19.

Regulatory Asset-Litigation	$ 20,607
Regulatory Liability-Pension	$ (7,608)
Regulatory Liability-Tax Gain	$(27,365)
South Georgia –Tax Step up	$ 13,584
Regulatory Asset-General Liability	$ 50,000

Total income taxes for the test year ended September 30, 2015 are projected using the projected taxable operating income less calculated interest expenses less deductions multiplied by the current state and federal tax rates. Timing differences were estimated by the corporate office of Chesapeake Utilities Corporation to determine the deferred tax amounts, as elaborated upon in Matt Kim's testimony. The difference between total income taxes and deferred taxes is current income taxes. These calculations are shown on MFR Schedules C-22 and C-23.

The 2015 projected investment tax credits are calculated from the Investment Tax Credit (ITC) amortization schedule for the electric utility division. There is no ITC amortization remaining for the projected test year and accordingly the projection is zero. Annual ITC balances and amortization details appear in schedule B-23.

Q. What was the basis for the storm reserve and expense included in the test year?

A. The Company has included a storm accrual expense of $10,135 a month, or

$121,620 a year for a total storm reserve of $2,900,000, which was initially approved in Commission Order PSC-08-0327-FOF-EI. The Company does not anticipate any requirements for an increase or decrease in the annual storm expense and perceives the reserve, with current accruals, is adequate to cover any future expected storms.

Q. What is the basis for the rate case expense included in the projected test year?

A. The Company has projected rate case expense based on specific forecasts including the cost to use consultants to assist in preparation and support of a rate case and the cost for representation and consultation by an attorney. The Company is not staffed at a level to allow for preparation of rate proceedings, MFRs or the additional rate case related work load required after the MFRs are filed. Internally, the work load has increased since our last electric rate case was filed without an offsetting increase in staff within the Company. We now require additional resources beyond the level required in our last electric rate case. Much of our accounting staff that had previously worked on the rate proceedings is no longer with the Company; thus, the overall experience level of staff members as it relates to this type of regulatory proceeding has declined as compared to our 2007 rate case. The Company does not have the expertise in all areas to help facilitate the preparation of a rate case; therefore, we hired the expertise and extra assistance to assist us with this process. The Company also had to utilize temporary accounting staff and consultants to assist in the extra rate case work beyond the normal work load of the regulatory department. MFR Schedule C-10 includes more details on these expenses. All costs expected to be incurred are prudent, and should be allowed for full recovery in this rate proceeding.

The Company included a 5-year amortization period for the Company's rate case expense. Use of the 5-year amortization period will allow the Company to spread the rate case expense over a slightly longer period of time, which will therefore reduce the impact on customers' bills. The Commission has allowed the Company to use a 5-year amortization period in the past. Specifically, in Order No. 22224, issued in Docket No. 881056-EI, on November 27, 1989, the Commission authorized the Company to use a 5-year amortization period for rate case expense. Therein, the Commission recognized that it is appropriate to amortize rate case expense over the period of time between rate case proceedings and then concluded that a 5-year period was appropriate for FPU. It is likewise reasonable to use a 5-year amortization period in this proceeding as well, in view of the fact that the time span between the Company's most recent prior rate case proceeding and this filing extends more than 6 years.

Q. What is the basis for the general liability expense and reserve included in the projected test year?

A. The Company has incurred a recent claim in its electric operations that is expected to reach the cap of the self-insurance portion of our general liability account. The Company is requesting that this claim be allowed as a regulatory asset and be amortized over five years beginning with the test year. In addition, the Company is requesting establishment of a self-insurance reserve, similar to the one already in place and approved by the Commission for FPUC Natural Gas, to cover future general liability claims, and is proposing to accrue $50,000 per year to cover large claims, and $20,000 of smaller claims on an annual basis for the basis of the self-insurance reserve. This expense has been reflected in O&M expenses as a direct projection. The worker's compensation and general liability components of this account have been projected by the corporate office and details regarding the current liability claim are reflected in the testimony of Matt Kim.

The self-insurance component of this account has been projected based on our claim history. Due to an increase in claims, we have projected an increase in the reserve of $250,000 over a five year period, effective October 2014, to amortize an existing claim and establish a reserve for future claims. We have included expenses of $120,000 in our projected test year, which accounts for some large claims in auto or general liability of $250,000 over five years, plus $20,000 per year for smaller claims.

Q. **What is basis for Economic Development expenses included in the projected test year?**

A. The Company has been involved and has participated in economic development activities in the areas it serves for many years. The Company is currently developing a more robust, detailed program to guide our economic development efforts, which involves new business assistance, community involvement, customer retention, education, and local chamber involvement. The Company's

Marketing Director expects that expenses will increase due to this enhanced program, as fully explained in the testimony of Company witness Aleida Socarras. The Company has directly projected economic development expenses of $50,000 less the prior expenses of $28,750. Therefore, we have adjusted the projected test year by $21,250 for our economic development efforts. In addition, the Company is requesting approval of a new economic tariff to promote new business in its electric operations. Both our panel witnesses Cutshaw and Shelley, as well as witness Socarras, provide additional details on the economic development costs and tariffs being proposed in this rate proceeding.

Q. Are there any other direct or over and under adjustments included in the projected test year and if so, what is the basis for this expense?

A. Yes. Over and under adjustments were made to the projected test year for operational costs for which the historic year was not reflective as a sole basis of future costs or savings. The reorganization of the Electric Operations with one Director overseeing the NW and NE Divisions resulted in savings of approximately $73,000 and this expense was removed. Tree trimming, pole attachment audits, industry association dues, legal and consulting as well as transportation depreciation were also adjusted to reflect a typical year. Due to new hires, organizational changes, or revised employee allocations made during the historic year, expenses were adjusted to reflect costs for a full year. Details of all of the Over and Under adjustments made to the historic year are provided on MFR Schedule C7.

Q. What was the basis for the projection of Taxes Other Than Income ("TOTI") included in the projected test year?

A. The TOTI taxes were projected using trend factors applied to historic year expenses as appropriate or most reflective of future expected expense levels. Payroll taxes were trended based on payroll and customer growth. The regulatory assessment fee, gross receipts tax and franchise fees were calculated based on projected revenues. Property taxes were increased by inflation and plant growth. These calculations are shown on MFR Schedule C-20.

Q. Does the Company feel that the expenses projected for the test year ending September 30, 2015 adequately reflect actual expected ongoing expenses?

A. Yes, the Company reviewed the results of its projections and concluded that the expenses projected reflect expected ongoing normal expenditures in the twelve month period ending September 30, 2015. The Company reviewed results and compared them to prior projections, historical results, known changes, and anticipated changes. To the best of our knowledge and based on our review, the expenses reflected in this rate proceeding are the most accurate and up-to-date expectations for ongoing expenses.

Q. What is the basis for the Corporate Expenses allocated to the Business unit included in the test year?

A. The Corporate expenses are directly projected by the corporate office of Chesapeake Utilities Corporation and are addressed in the testimony of Matt Kim.

Q. How does the company allocate costs for corporate charges across the different utility services?

A. Whenever it is possible and practical, corporate expenses are directly assigned to the business unit incurring such cost. Corporate expenses that cannot be directly assigned are allocated among Chesapeake Utilities Corporation's business units that receive benefit from such functions and services. Chesapeake Utilities Corporation utilizes various methodologies in allocation of costs, depending on the type of expense. These methodologies are designed to reflect the relative size and benefit of each business unit receiving the shared functions and services and may include consideration of direct payroll, profitability, adjusted gross plant, investment and customers, among others, in determining the allocation basis. While Chesapeake Utilities Corporation utilizes different methodologies depending upon the type of expense, it uses the consistent methodology among all of its business units in allocating the same type of expense. The allocation methodologies are described in greater detail in Matt Kim's testimony. Chesapeake Utilities Corporation reviews and updates the allocation basis at least annually at the beginning of each fiscal year.

Q. **How does the Company allocate costs for Business Unit charges?**

A. Business unit charges are directly assigned to the business unit incurring the cost when feasible. Some expenses incurred by the FPU management and employees are allocated among only the Florida business units, allocating to those specific business units receiving the shared functions and services. As such, FPU utilizes various methodologies in allocation of costs, depending on the type of expense.

These methodologies may include customers, time studies/managers expert opinion, plant, and investment, among others, in determining the allocation basis and are consistent with prior approved methods authorized in prior rate proceedings for FPU. FPU management reviews and updates the allocation basis at least annually at the beginning of each year or as material changes warrant. The allocation basis used distributes expenses to the appropriate specific business units.

Q. What is the reason for the increase to Administrative & General (A & G) expenses for the projected test year over and above the inflation and customer growth since the last rate proceeding?

A. There are several reasons for the increase to A & G expenses. First, in the projected 2015 test year, $66,156 of common depreciation expense was included in Account 921. In the benchmark year, those charges were included in Account 403-Depreciation expense. Also, the 2015 projected year included rent expense of $124,609 that was not included in the benchmark year. The increase in rent expense is offset by reductions to rate base, depreciation expense, and taxes other than income that would have been included if the West Palm Beach corporate office was not sold. Likewise, the 2015 projected year included an increase to administrative and general insurance expense of $120,000 to establish a general liability reserve and to amortize a 2014 claim over five years. This reserve is in lieu of purchased insurance and reduces the volatility associated with periodic claims. Technology cost also increased by approximately $350,000. The remaining increase relates to additional travel costs and expanded corporate functions and services not previously available to FPU. Travel costs have increased because of centralization of the Florida staff, additional training available to employees and increased focus in customer service and employee satisfaction, which require managers to travel to all locations within Florida. The transfer of certain A & G functions to the corporate office in Delaware for increased quality and efficiency has also necessitated additional travel. Since the merger with Chesapeake in 2009, FPU has benefited from certain corporate functions, such as corporate communications and business development, which were not previously available to FPU. Better company-wide training, communications and website contents provide our employees with information necessary to provide superior customer service and increase customer engagement for higher satisfaction. See Matt Kim's testimony for additional information on A&G expenses and the reason for the variance.

Q. What is the reason for the increase in customer related expenses?

A. Customer-related expenses increased due to new customer service initiatives which included more customer service personnel, better customer systems, and an increase in service monitoring and education. This is appropriate because these initiatives allow us to better serve our customers. All costs have been prudently incurred and directly benefit the customers we serve. The testimony of Mariana Perea provides details on the customer service initiatives.

Q. What is the reason for the increase in marketing expenses?

A. Marketing expenses increased because of an increase in community awareness and notification campaigns and events which were designed to increase customers' awareness of changes taking place and what they may expect. The campaign to explain Time-Of-Use rates is an example of the type of campaigns that occurred in the historic year to better educate the customers on how to reduce their bill. The projected test year included costs for similar types of campaigns in addition to informing customers of purchased power rate changes that occur each year.

Q. What was the reason for the decrease in total transmission and distribution expense in the projected test year compared to the prior rate proceeding benchmarked to the same period?

A. These costs decreased primarily because the overall reliability of these systems was significantly improved as a result of Chesapeake's system improvement initiatives. We also centralized certain operating functions, which further contributed to the efficiency of these systems. As a direct result of these system improvements, the Company was able to significantly reduce the costs in this area over the prior rate case in today's terms; most notably, maintenance costs are down compared to the benchmark period. Despite savings, some costs increased over the bench mark period due to other Company efforts aimed at upgrading the overall quality and efficiency of our electric operations. Some of these efforts produced increased costs in the short term, but are expected to lead to lower costs, and increased efficiencies, in the long term. Among these efforts, some of which are ongoing, is our effort to assess fuel supply alternatives that will lead to lower fuel and purchased power costs for the Company and its ratepayers. Another significant factor impacting cost increases has been the actual inflationary impact on goods and services, as further outlined below. Meter expenses and other reliability-related operating costs also increased over the bench mark period, because we upgraded meters and other similar equipment, which led to similar additional expenses. Moreover, the Company has invested time and effort on ongoing training, employee development, safety enhancements, and improved communication, thereby adding to the increase in some costs over the prior rate proceeding but resulting in better service to our customers. As a result, customers directly benefit through better service, more knowledgeable and trained personnel and a more reliable system.

Also, as noted, the actual impact of inflation on payroll and goods was higher than the CPI-U factor would indicate; thus, a portion of the variance is attributable to an artificially low expectation on the true inflationary impact on costs. Management continually strives to improve the efficiency and effectiveness of our electric system, and to provide superb customer support and service at a prudent and reasonable cost to our customers.

Q. Is the O&M Compound multiplier factor which includes customer growth and inflation, appropriate to use for analysis of cost increases since the last rate proceeding?

A. No, although the factor generally considers the impact on costs due to inflation and customer growth, the economic conditions that existed in a few of the years during the benchmark period are not appropriate for measuring the true cost of inflation on goods and services during the same period. There were several abnormal years in terms of inflation that impacted the CPI-U factor. Despite having a computed inflation factor based on CPI-U that was negative in year 2008 to 2009; actual cost increases experienced during that period did not see the same rate of change due to inflation. The economic downturn and CPI-U factor was impacted by an unusual housing market and high unemployment. The Company did not experience those same decreases in payroll or in the cost of materials and supplies purchased during the benchmark period. A portion of the variance in costs compared to the bench mark periods is attributable to actual cost increases not matching the inflation factor shown in the CPI-U factors.

Q. Have there been any new positions included in the projected test year over the historic year?

A. We did not include any new positions in the projected test year, but we did include adjustments (over and under) for the promotions of two Assistant Operations Managers to Operations Managers in February 2014 which resulted from the reorganization of the Electric Operations to establish one Director overseeing both the NW and NE Divisions.

Q. **Have there been any positions eliminated in the projected test year compared to the historic year?**

A. Yes, the Company removed a portion of one position that will be allocated to other business units in Florida due to a change in job responsibilities. The "over and above" adjustment removes the portion of the payroll and related benefits that does not belong in electric operations.

Q. Are the payroll expenses incurred by the Company fair, appropriate and reasonable and appropriate for recovery in this rate proceeding?

A. Yes, FPU strives to be an employer of choice. Our goal is to attract and retain top talent. Customers benefit from our ability to employ and retain this talent through their abilities to perform the work that directly benefits our customers as well as indirectly benefits through optimal work efficiency and performance. We participate in annual compensation surveys to compare our salary ranges with the industry. We strive to pay Job Market Value to ensure we are able to compete in attracting top talent. In assessing what Job Market Value is for employees, we review a variety of annual compensation studies including the AGA (American Gas Association) Study; Payscale, Compdata Survey and other industry related studies/benchmarks. The Company also prepares detailed compensation studies on a periodic basis. For 2014, we have hired outside consultants (THEaster and Associates) to conduct a company-wide salary survey and revise and update job descriptions. The current salary ranges that are in place were based on a detailed study that was completed in 2011, which has been updated annually to reflect inflationary payroll impacts to those same ranges. In addition to paying competitive base salaries, an Incentive Performance Plan rewards employees for reaching individual and Company annual goals. This portion of pay is considered as part of normal compensation and was considered in establishing the appropriate salary ranges for positions. Making a portion of "pay" part of an incentive plan based on achieving goals is effective in ensuring that our employees meet the highest of standards in performance.

Additionally, union contracts determine pay increases for our union employees. All contracts have been prudently and fairly negotiated; however, these do impact the total payroll and benefits the Company is required to compensate union employees.

Total compensation includes reasonable and standard benefits for our full time employees including:

- 401(k) Savings Plan that matches $1 for $1 up to 6% of base salary.
- Short Term Disability (At no cost to the employee, they receive 60% of pay for extended illnesses after 7 days through Cigna).
- Long Term Disability (At no cost to employee, they receive 60% of base pay for extended illnesses after 90 days through Cigna).
- PTO days ranging from 14 – 29 per year depending on years of service.
- 10 Sick Days per year accrued.
- Tuition Reimbursement.
- Medical and Dental Benefits. Company pays a portion of the premiums.

Payroll as projected is fair, reasonable and appropriate for purposes of determining projected year expenses.

Q. **Are the maintenance expense amounts included in the test year appropriate for the purposes of setting base rates?**

A. Yes, overall maintenance expense levels are appropriate as projected in the test year; however, some of the specific periodic projects and amounts in maintenance accounts may vary from year to year. The projected test year reflects ongoing expense levels necessary to operate its system in a reliable, safe, and properly maintained manner. The Company, when feasible, takes the approach of spreading out required periodic maintenance projects over a period of time. This approach does not unduly burden the customers or the Company resources; yet, maintains the system in a safe and efficient manner.

Q. Are the expenses reflected in the projected test year prudent and reasonable?

A. Our expenses are prudently incurred. We have only sought cost recovery of expenses necessary to provide consistent reliable service to our customers. To that end, FPU has effectively and efficiently managed and controlled costs. In fact, since the merger, the Company's efficiencies have resulted in reduction of certain costs in certain areas enabling us to expand provided services and benefits to customers thereby keeping rates stable for as long as possible.

Q. **Does the net operating income used in the rate proceeding projection equal the company's budget that is used for financial reporting and if not, why?**

A. No, the Company prepared the current internal net operating income budget for the projected calendar years 2014 and 2015 during the summer of 2013, while the rate proceeding projections were based on more current expectations. Although the Company considered the items in the internal budget for purposes of the projections for this rate proceeding, a historic actual expense forward projection was used for the business unit forecast. Actual expenses were adjusted for out of period items and normalized for re-classifications between FERC accounts. These normalized and adjusted expenses were trended when appropriate and adjusted to reflect known items over or under those projections. The corporate forecast was prepared using the budget as a starting point and adjusted as appropriate to reflect current expectations. Matt Kim's testimony includes more details regarding that forecast. In addition, the internal budget is not budgeted to the same level of FERC detail that was performed in this rate proceeding forecast.

Also, since the internal budget was prepared in the summer of 2013, it did not include certain expenses pertinent to this rate proceeding. The key differences between the internal budget prepared in the summer of 2013, compared to the updated forecast reflected in this rate proceeding are as follows:

Amortization associated with the regulatory asset-pension	$274,000
Rate case amortization	$154,000
Amortization of general liability regulatory asset	$ 50,000
Accrual of general liability expense (establishment of reserve)	$ 70,000

Revenues were projected for the rate proceeding on a much more detailed basis than the internal budget with more extensive analysis to determine the appropriate billing determinants. The revenues used in this rate proceeding are the best forecast for expected revenues in the projected test year. Robert Camfield's testimony includes additional information regarding these projections.

Q. Are the revenues and expenses as projected in the test year ending September 30, 2015 appropriate for rate setting purposes?

A. Yes, the revenues and expenses reflect the prudently incurred expenses and expected revenues at current rates for the projected test year. The projected test year revenues and expenses reflected in the MFR Schedule Cs are appropriate for rate setting purposes.

Cost of Capital

Q. Please explain the basis for the projections included in MFR, Schedules D to compute the overall rate of return.

A. The Corporate offices of Chesapeake Utilities Corporation provided projections of the Chesapeake Utilities Corporation's overall capital structure for the projected years ending September 30, 2014 and 2015 included in MFR Schedule D-1 for common equity, long term debt, short term debt, and deferred taxes. Witness Kim's testimony includes and explains the methodology used to project these cost of capital components. Schedule D-1b discusses the reason for the specific equity adjustment included in Schedule D-1 which will be also be discussed further testimony provided by Matt Kim and Paul Moul. Schedule D-4a details the long term debt by issuance for both FPU and Chesapeake. Schedule D-3 includes the test year and projected short term debt along with a narrative of Chesapeake's policies on short term financing. The Company policy on the timing of entrance into capital markets is outlined in Schedule D-8. Customer Deposits for FPU electric were projected based on the historical year-end balance at September 30, 2013 and applying the customer growth rate to those balances. The cost rate was based on the historical year average cost rate, applied to the projected balance of customer deposits. The interest rates for customer deposits are paid in accordance with the rules and regulations required. Schedule D-6 in the MFRs contains the forecast for customer deposits. Deferred taxes for FPU electric were projected based on separate projections of each timing difference. A detailed projection was made for deferred taxes based on the timing differences expected. Depreciation expense was computed for tax purposes based on the specific capital projections included in this filing as part of the deferred tax estimate. This projection of deferred taxes is discussed further in witness Kim's testimony. The Company hired an expert in Cost of Capital analyses, witness Paul Moul, to assist with developing the overall capital structure and cost rates utilized in our MFR D Schedules, and he has also provided additional supporting testimony regarding our cost of capital.

Q. Please discuss the long term debt schedule included in the filing.

A. Schedule D-4a is broken in to two segments, FPU's debt and Chesapeake's debt. FPU's debt was originally issued by FPU before the merger with Chesapeake and the FPU debt has only been allocated to the original FPU divisions. The remainder of Chesapeake corporate debt was allocated to the electric operations based on the pro-rated overall percentage of Chesapeake debt to equity less the directly assigned FPU debt. This methodology is discussed further in witnesses Matt Kim's and Paul Moul's testimonies.

Q. What is the capital structure of the Company?

A. As discussed in depth by witness Moul, the projected capital structure of the company consists of 46.45% equity, 28.2% long term debt, and 5.19% short term debt. The rest of the capital structure is composed of direct components of the electric division. The overall weighted average cost of capital for the projected test year is 7.18%.

Q. How do the ratios compare with other electric utilities?

A. The 7.18% weighted average cost rate is comparable to other utilities in the State of Florida. The Common Equity ratio is also comparable to other major electric utilities in the state of Florida. Witness Moul also provides additional explanation regarding the ratios and cost rates.

Q. Has the merger with Chesapeake had an impact on FPU's overall cost of debt?

A. Yes. For instance, the debt rate in the 2006 rate case was 8.03%. In the current projections for 2015, the Chesapeake debt rate is 4.89%. The overall weighted cost of capital has decreased from 8.18% in 2006 to 7.18% in the projected test year.

Q. Let's discuss the basis for your projections of the various capital components. Are there any capital components that you have excluded from this filing that were included in the last rate case?

A. Yes, the Company no longer has preferred stock, which amounted to $600,000 in 2006 and was .0049% of the capital structure.

Q. Please explain how the projected amounts for deferred taxes and income tax credits were derived?

A. Witness Kim's testimony discusses these components in more detail. In summary detailed projections were made for expected deferred taxes using expected timing differences including depreciation expense for tax purposes. ITC has been fully amortized, and is projected to be zero for the test year.

Q. How did you determine the amount reflected for customer deposits?

A. Average customer deposits for the historic year ended September 30, 2013 was trended by customer growth expected for the two projected years to estimate the customer deposits included in the capital structure.

Q. Is this consistent with the methodology approved by the Commission for FPU in the Company's 2007 rate case?

A. Yes, the Company used this same forecast basis for customer deposits in the prior rate case.

<u>Consolidated Fuel Rates and Impact to Fuel from Generation Project</u>

Q. Please explain the need to consolidate Fuel rates for 2015 and the relative fairness issue related to this base rate proceeding.

A. The Company has transmission assets embedded in its base rates for the Consolidated Electric Division, but similar assets to serve the customers located in the NW division are owned by Gulf Power Company and the related rates are passed on to our NW division thru the fuel rates charged to just those customers. The Company had originally requested the consolidation of its fuel rates for these divisions in conjunction with the consolidation of base rates in our prior proceedings; however, the Commission approved the consolidation of base rates but not fuel rates. Accordingly, the Company recently requested a special allocation in the Fuel Clause to deal with the transmission related costs, and the fairness of associated rates. The Commission approved this allocation in the 2014 fuel rates; but, required that the Company consider and address consolidation of fuel rates in the 2015 Fuel Clause. The Company may, consequently, request that the Commission allow the Company to consolidate its fuel rates in through the upcoming Fuel Clause for the calendar year 2015. In the mean time, the Commission approved the allocation methodology currently used for the fuel rates for 2014 which addresses the fairness issue and customers are being billed the appropriate fuel rates. While the Company intends to address fuel rate consolidation in the context of Docket No. 140001-EI, as directed by the Commission, the Company does offer an alternative approach that could be considered in this proceeding. This alternative would remove the subject transmission assets entirely from rate base now, and allow recovery of these assets, along with expenses and return on assets, through the Fuel Clause in a manner consistent with the approved allocation of transmission related expenses for 2014.

Q. The Company expects to realize savings to its customers from a Power Generation Project in its NE division. What is the estimated savings to customers as a result of this project?

A. The Company is taking a number of measures to mitigate cost pressures and improve electricity services to retail consumers in the Northeast and Northwest Division. These changes include both tactical and strategic actions. An example of strategic actions is our newly formed power generation subsidiary, Eight Flags Energy LLC (Eight Flags), in the Northeast Division. As discussed in Mark Cutshaw's testimony, Eight Flags is expected to begin with a [redacted]

[redacted] which will substantially reduce the costs of power paid by retail consumers.

Because of its inherent technical efficiency and proximity on the Amelia Island, the Eight Flags project will also result in improved reliability and reduced environmental emissions. As addressed in the panel testimony of witnesses Cutshaw and Shelley, Eight Flags Energy is expected to provide net benefits of [redacted], during the initial two years of operation, 2016 and 2017, respectively. Over its initial ten years of operation, 2016-2025, the Company's Eight Flags cogeneration plant is expected to provide a total of direct net benefits of [redacted], stated on a nominal and discounted basis respectively.

Q. Is there anything that the Company can suggest to help bridge the gap between the base rate increases expected in 2015 as a result of this base rate proceeding, and the fuel cost decrease expected to begin in 2016?

A. One option that the Company will explore is to seek Commission approval in the Fuel Clause proceeding to allow the Company to under recover fuel costs in 2015 in order to offset some of the base rate increase. The Company would then recover the under-recovery in fuel over a three-year period when savings are expected to be realized as a result of the new generation project. This will provide relief from rate shock to our customers, and phase in the increase and decrease associated with the base rate increase, and fuel cost decrease, respectively. In other words, to avoid potential rate shock of a requested 6.79% increase on total revenues for the requested base rate change in 2015, and the expected fuel cost decrease of [redacted] on total revenues for the fuel rate change in 2016 and beyond, the Company may request a phased-in approach to this fuel cost decrease, and offset some of the increase in the bridge year of 2015. Customers would have a "one year gap" of base revenue increase without corresponding decrease in fuel costs. This gap could be collected over a three year period thus reducing the volatility associated with changing overall rates to customers.

Q. Are there any changes to the fuel rates required or requested at the time of this rate proceeding?

A. Yes, but only as a result of the consolidation of Outdoor and Streetlight tariffs requested in this base rate proceeding, which, if approved, would necessitate that fuel rates for these rate classes be combined as well. The panel testimony of witnesses Cutshaw and Shelley includes additional details surrounding this change to fuel rates and a related exhibit which computes the new fuel rates associated with the new Lighting tariffs.

Summary

Q. Please summarize your testimony.

A. As is clearly demonstrated, the Company has been, and is, currently below the low point of our allowable return. Without rate relief, the Company is expected to continue to earn a return well below its allowable rate of return. If that continues, this will jeopardize our ability to provide sufficient, consistent reliable service to our customers.

FPU is requesting a permanent increase in the electric rates and charges in the amount of $5,852,171 in order to cover the deficiencies in revenues for the projected September 30, 2015 test year. This required revenue is based on a rate of return equal to 7.18% and a projected rate base of $60,596,169.

Florida Public Utilities Company is also requesting interim rate relief in the amount of $2,433,314 in annual electric rates and charges. Stated in percentage terms, we seek an interim increase in revenues equal to 14.91% on base rates and charges. The interim rate increase is based on a weighted average cost of capital equal to 6.37% and a September 30, 2013 year end rate base of $54,511,326.

Furthermore, the Company has appropriately, fairly, and prudently projected the September 30, 2015 test year Net Operating Income, Rate Base and Cost of Capital; and as such, it should be used as a basis to determine the revenue requirement.

Q. Does this conclude your testimony?

A. Yes.

MFR'S Sponsored by Cheryl Martin

MFR Number	Title
A-1	Full Revenue Requirements Increase Requested
A-2	Full Revenue Requirements Bill Comparison-Typical Monthly Bills
A-3	Summary of Tariffs
A-4	Interim Revenue Requirements Increase Requested
A-5	Interim Revenue Requirements Bill Comparison-Typical Monthly Bills
B-1	Adjusted Rate Base
B-2	Rate Base Adjustments
B-3	13 Month Average Balance Sheet-System Basis
B-4	Two Year Historical Balance Sheet
B-5	Detail Changes in Rate Base
B-6	Jurisdictional Separation Factors-Rate Base
B-7	Plant Balances by Account and Sub-Account
B-8	Monthly Plant Balances Test Year-13 Months
B-9	Depreciation Reserve Balances by Account and Sub-Account
B-10	Monthly Reserve Balances Test Year-13 Months
B-11	Capital Additions and Retirements
B-12	Production Plant Additions
B-13	Construction Work in Progress
B-14	Earnings Test
B-15	Property Held for Future Use-13 Month Average
B-16	Nuclear Fuel Balances
B-17	Working Capital-13 Month Average
B-18	Fuel Inventory by Plant
B-19	Miscellaneous Deferred Debits
B-20	Other Deferred Credits
B-21	Accumulated Provision Accounts-228.1,228.2 and 228.4
B-22	Total Accumulated Deferred Income Taxes
B-23	Investment Tax Credits-Annual Analysis
B-24	Leasing Arrangements
B-25	Accounting Policy Changes Affecting Rate Base
C-1	Adjusted Jurisdictional Net Operating Income
C-2	Net Operating Income Adjustments
C-3	Jurisdictional Net Operating Income Adjustments
C-4	Jurisdictional Seperation Factors-Net Operating Income
C-5	Operating Revenues Detail
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-7	Operation and Maintenance Expenses
C-8	Detail of Changes in Expenses
C-9	Five Year Analysis -Change in Cost
C-10	Detail of Rate Case Expenses for Outside Consultants
C-11	Uncollectible Accounts
C-12	Administrative Expenses
C-13	Miscellaneous General Expenses
C-14	Advertising Expenses
C-15	Industry Association Dues
C-16	Outside Professional Services
C-17	Pension Cost
C-18	Lobbying Expenses, Other Political Expenses & Civic/Charitable Contributions
C-19	Amortization/Recovery Schedule-12 Months
C-20	Taxes Other than Income Taxes
C-21	Revenue Taxes
C-22	State and Federal Income Tax Calculation
C-23	Interest In Tax Expense Calculation
C-24	Parent(s) Debt Information
C-25	Deferred Tax Adjustment
C-29	Gains and Losses on Disposition of Plant or Property
C-30	Transactions with Affiliated Companies
C-31	Affiliated Company Relationships
C-32	Non-Utilitiy Operations Utilizing Utility Assets
C-33	Performance Indices
C-35	Payroll and Fringe Benefit Increases Compared to CPI
C-36	Non-Fuel Operation and Maintenance Expense Compared to CPI
C-37	O & M Benchmark Comparison by Function
C-38	O & M Adjustments by Function
C-39	Benchmark Year Recoverable O & M Expenses by Function
C-40	O & M Compound Mutiplier Calculation
C-41	O & M Benchmark Variance by Function
C-42	Hedging Costs
C-43	Security Costs
C-44	Revenue Expansion Factor

MFR'S Sponsored by Cheryl Martin

MFR Number	Title
D-1a	Cost of Capital-13 Month Average
D-1b	Cost of Capital-Adjustments
D-2	Cost of Capital-5 Year History
D-3	Short Term Debt
D-4a	Interim Revenue Requirements Bill Comparison-Typical Monthly Bills
D-6	Customer Deposits
D-7	Common Stock Data
D-8	Financing Plans-Stock and Bonds Issues
D-9	Finacial Indicators-Summary
F-5	Forcasting Models
F-6	Forcasting Models-Sensitivity of Output to Change Input Data
F-8	Assumptions
F-9	Public Notice
G-1	Interim Revenue Requirements Increase Requested
G-2	Interim Adjusted Rate Base Year- End
G-3	Interim Rate Base AdjustmentsYear-End
G-4	Interim Jurisdictional Separation Factors-Rate Base
G-5	Interim Working Capital-13 Month Average
G-6	Interim Fuel Inventory by Plant
G-7	Interim Adjusted Jurisdictional Net Operating Income
G-8	Interim Net Operating Income Adjustments
G-9	Interim Jurisdictional Net Operating Income Adjustments
G-10	Interim Jurisdictional Separation Factors-Net Operating Income
G-11	Interim Operating Income Detail
G-12	Interim State and Federal Income Tax Calculation
G-13	Interim Interest In Tax Expense Calculation
G-14	Interim Parent(s) Debt Information
G-15	Interim Gains and Losses on Disposition of Plant or Property
G-18	Interim Revenue Expansion Factor
G-19b	Interim Cost of Capital-Adjustments

Amortization - Regulatory Asset - Pension and Other Post Retirement Benefits
Order No. PSC-08-0134-PAA-PU
Docket No. 080029-PU

		Amount			Amount
Pension:		7,519,327.00	OPRB:		87,360.00
	Electric	2,706,958.00		Electric	31,450.00
	Natural Gas	4,812,369.00		Natural Gas	55,910.00
Amortization: 9.88 years			Amortization: 11.3 years		
(Electric Only)	Annually	273,984.00	(Electric Only)	Annually	2,783.00
	Monthly	22,832.00		Monthly	232.00

Exhibit NO. _____
DOCKET NO. 140025-EI
WITNESS: CHERYL M. MARTIN
EXHIBIT NO. CMM-2
PAGE 1 of 2

BALANCE SHEET

HISTORIC YEAR

	Sept 2012	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	13-mo total	13 month avg.
Pension	4,875,288	4,852,456	4,829,624	4,806,792	6,111,229	6,088,397	6,065,565	6,042,733	6,019,901	5,997,069	5,929,599	5,906,767	5,883,935	73,409,358	
FAS 158-Pension adj. OCI				1,327,269						(44,638)			(22,319)	1,260,312	
Amortization Booked	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(296,816)	
Balance 1781-1823	4,852,456	4,829,624	4,806,792	6,111,229	6,088,397	6,065,565	6,042,733	6,019,901	5,997,069	5,929,599	5,906,767	5,883,935	5,838,784	74,372,854	5,720,989
OPRB	408,035	407,803	407,571	407,339	41,892	42,559	42,327	42,095	41,863	41,632	41,400	41,168	40,936	2,006,621	
FAS 158-OPRB adj. OCI				(365,215)	899									(364,316)	
Amortization Booked	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(3,015)	
Balance 1781-1823	407,803	407,571	407,339	41,892	42,559	42,327	42,095	41,863	41,632	41,400	41,168	40,936	40,704	1,639,289	126,099
TOTALS															
Pension & OPRB	5,283,323	5,260,259	5,237,195	5,214,131	6,153,121	6,130,956	6,107,893	6,084,829	6,061,765	6,038,701	5,970,999	5,947,935	5,924,871	75,415,978	-
FAS 158-adj. OCI	-	-	-	962,054	899	-	-	-	-	(44,638)	-	-	(22,319)	895,996	-
Amortization Booked	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(299,831)	-
	5,260,259	5,237,195	5,214,131	6,153,121	6,130,956	6,107,893	6,084,829	6,061,765	6,038,701	5,970,999	5,947,935	5,924,871	5,879,488	76,012,144	5,847,088

PRIOR YEAR

	Sept 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	13-mo total	13 month avg.
Pension	5,883,935	5,838,784	5,815,953	5,793,121	3,022,969	3,000,137	2,977,305	2,954,473	2,931,641	2,908,809	2,885,977	2,863,145	2,840,313	49,716,560	
FAS 158-Pension adj. OCI	(22,319)			(2,747,320)										(2,769,639)	
Amortization Booked	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(296,815)	
Balance 1781-1823	5,838,784	5,815,953	5,793,121	3,022,969	3,000,137	2,977,305	2,954,473	2,931,641	2,908,809	2,885,977	2,863,145	2,840,313	2,817,481	46,650,105	3,588,470
OPRB	40,936	40,704	40,472	40,240	(5,439)	(5,671)	(5,903)	(6,135)	(6,367)	(6,599)	(6,831)	(7,062)	(7,294)	105,051	
FAS 158-OPRB adj. OCI	-			(45,447)										(45,447)	
Amortization Booked	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(3,015)	
Balance 1781-1823	40,704	40,472	40,240	(5,439)	(5,671)	(5,903)	(6,135)	(6,367)	(6,599)	(6,831)	(7,062)	(7,294)	(7,526)	56,589	4,353
TOTALS															
Pension & OPRB	5,924,871	5,879,488	5,856,424	5,833,361	3,017,530	2,994,466	2,971,402	2,948,338	2,925,274	2,902,210	2,879,146	2,856,082	2,833,019	49,821,611	-
FAS 158-adj. OCI	(22,319)	-	-	(2,792,767)	-	-	-	-	-	-	-	-	-	(2,815,086)	-
Amortization Booked	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(299,831)	-
	5,879,488	5,856,424	5,833,361	3,017,530	2,994,466	2,971,402	2,948,338	2,925,274	2,902,210	2,879,146	2,856,082	2,833,019	2,809,955	46,706,695	3,592,823

PROJECTED TEST YEAR

	Sept 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	13-mo total	13 month avg.
Pension	2,840,313	2,840,313	2,794,649	2,771,817	2,748,985	2,726,153	2,703,321	2,680,489	2,657,657	2,634,825	2,611,993	2,589,161	2,566,329	35,166,007	
FAS 158-Pension adj. OCI	-													-	
Amortization Booked	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(296,815)	
Balance 1781-1823	2,817,481	2,817,481	2,771,817	2,748,985	2,726,153	2,703,321	2,680,489	2,657,657	2,634,825	2,611,993	2,589,161	2,566,329	2,543,497	34,869,192	2,682,246
OPRB	(7,294)	(7,294)	(7,758)	(7,990)	(8,222)	(8,454)	(8,686)	(8,918)	(9,150)	(9,382)	(9,613)	(9,845)	(10,077)	(112,683)	
FAS 158-OPRB adj. OCI	-													-	
Amortization Booked	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(3,015)	
Balance 1781-1823	(7,526)	(7,526)	(7,990)	(8,222)	(8,454)	(8,686)	(8,918)	(9,150)	(9,382)	(9,613)	(9,845)	(10,077)	(10,309)	(115,698)	(8,900)
TOTALS															
Pension & OPRB	2,833,019	2,833,019	2,786,891	2,763,827	2,740,763	2,717,699	2,694,635	2,671,572	2,648,508	2,625,444	2,602,380	2,579,316	2,556,252	35,053,324	-
FAS 158-adj. OCI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization Booked	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(299,831)	-
	2,809,955	2,809,955	2,763,827	2,740,763	2,717,699	2,694,635	2,671,572	2,648,508	2,625,444	2,602,380	2,579,316	2,556,252	2,533,188	34,753,494	2,673,346

Amortization - Regulatory Asset - Pension and Other Post Retirement Benefits
Order No. PSC-08-0134-PAA-PU
Docket No. 080029-PU

INCOME STATEMENT

HISTORIC YEAR	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	13-mo total
Amortization Expense - Pension	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(273,984)
Amortization Expense - OPRB	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(2,783)
Total	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(276,767)

PRIOR YEAR	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	13-mo total
Amortization Expense - Pension	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(273,984)
Amortization Expense - OPRB	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(2,783)
Total	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(276,767)

PROJECTED TEST YEAR	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	13-mo total
Amortization Expense - Pension	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(22,832)	(273,984)
Amortization Expense - OPRB	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(2,783)
Total	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(23,064)	(276,767)

Regulatory Asset - Litigation / Gulf Refund
Order No. PSC-12-0600-PAA-EI
Docket No. 120227-EI
and
Order No. PSC-13-0599-PAA-EI
Docket No. 130233-EI

Regulatory Asset	1,869,656.79
Gulf Power Refund - Amendment 1	1,766,623.88
	103,032.91
Annual Amortization	20,606.58
Monthly Amortization	1,717.22

Exhibit NO.____
DOCKET NO. 140025-EI
WITNESS: CHERYL M. MARTIN
EXHIBIT NO. CMM-3
PAGE 1 of 1

BALANCE SHEET

HISTORIC YEAR

Per Books	Sept 2012	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	**Sep 2013**	13-mo total	**13 month avg.**
Marianna Litigation				1,424,271	1,598,389	1,666,717	1,661,760	1,674,879	1,674,879	1,674,879	1,674,879	1,869,657	**1,869,657**	16,789,968	**1,291,536**
Amortization Booked					(26,640)	(54,438)	(82,150)	(110,093)	(138,035)	(165,978)	(193,921)	(225,538)	**(280,449)**	(1,277,242)	**(98,249)**
Balance 1772-1823	-	-	-	1,424,271	1,571,749	1,612,280	1,579,610	1,564,786	1,536,844	1,508,901	1,480,959	1,644,119	**1,589,209**	15,512,727	**1,193,287**
Adjusted Balance Sheet															
Marianna Litigation				1,424,271	1,598,389	1,666,717	1,661,760	1,674,879	1,674,879	1,674,879	1,674,879	1,869,657	**1,869,657**	16,789,968	**1,291,536**
Amortization Ordered					(1,717)	(3,434)	(5,151)	(6,868)	(8,585)	(10,302)	(12,019)	(13,736)	(15,453)	(77,265)	**(5,943)**
Gulf Power Refund								(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	**(1,766,624)**	(10,599,744)	**(815,365)**
Adjst'dBalance 1772-1823	-	-	-	1,424,271	1,596,672	1,663,283	1,656,609	(98,613)	(100,330)	(102,047)	(103,764)	89,297	**87,580**	6,112,959	**470,228**
														Adjustment	**(723,059)**

PRIOR YEAR

Adjusted Balance Sheet	Sept 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	**Sep 2014**	13-mo total	**13 month avg.**
Marianna Litigation	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	**1,869,657**	24,305,543	**1,869,657**
Amortization Ordered	(15,453)	(17,170)	(18,887)	(20,604)	(22,321)	(24,038)	(25,755)	(27,472)	(29,189)	(30,906)	(32,623)	(34,340)	(36,057)	(334,815)	**(25,755)**
Gulf Power Refund	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	**(1,766,624)**	(22,966,112)	**(1,766,624)**
Balance 1772-1823	87,580	85,863	84,146	82,429	80,712	78,995	77,278	75,561	73,844	72,127	70,410	68,693	**66,976**	1,004,616	**77,278**

PROJECTED TEST YEAR

Adjusted Balance Sheet	Sept 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	**Sep 2015**	13-mo total	**13 month avg.**
Marianna Litigation	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	1,869,657	**1,869,657**	24,305,543	**1,869,657**
Amortization Ordered	(36,057)	(37,774)	(39,491)	(41,208)	(42,925)	(44,642)	(46,359)	(48,076)	(49,793)	(51,510)	(53,227)	(54,944)	(56,661)	(602,667)	**(46,359)**
Gulf Power Refund	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	(1,766,624)	**(1,766,624)**	(22,966,112)	**(1,766,624)**
Balance 1772-1823	66,976	65,259	63,542	61,825	60,108	58,391	56,674	54,957	53,240	51,523	49,806	48,089	**46,372**	736,764	**56,674**

INCOME STATEMENT

HISTORIC YEAR	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	**13-mo total**
Amortization Expense per Books				26,640	27,798	27,712	27,943	27,942	27,943	27,943	31,617	54,911	**280,449**
Amortization Expense per Order				1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	**15,453**
Adjustment													**(264,996)**
PRIOR YEAR													
Amortization Expense per Order	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	**20,604**
PROJECTED TEST YEAR													
Amortization Expense per Order	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	**20,604**

Florida Public Utilities
Amortization - Regulatory Asset - South Georgia Method

Exhibit NO. ____
DOCKET NO. 140025-EI
WITNESS: CHERYL M. MARTIN
EXHIBIT NO. CMM-4

HISTORIC YEAR

	Sept 2012	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	13-mo total	13 month avg.
South Georgia Method	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	**248,666**	3,232,658	**248,666**
Amortization	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	**-**
Balance 1752-1823	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	248,666	**248,666**	3,232,658	**248,666**

PRIOR YEAR

	Sept 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	13-mo total	13 month avg.
South Georgia Method	248,666	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	**353,307**	4,488,350	**345,258**
Amortization	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	**-**
Balance 1752-1823	248,666	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	353,307	**353,307**	4,488,350	**345,258**

PROJECTED TEST YEAR

Adjusted Balance Sheet	Sept 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	13-mo total	13 month avg.
South Georgia Method	353,307	353,307	352,175	351,043	349,911	348,779	347,647	346,515	345,383	344,251	343,119	341,987	340,855	4,518,279	**347,560**
Amortization	-	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	(13,584)	**(1,045)**
	353,307	352,175	351,043	349,911	348,779	347,647	346,515	345,383	344,251	343,119	341,987	340,855	**339,723**	4,504,695	**346,515**

Regulatory Liability-Tax Gain
Depreciation on Vehicles
Order NO. PSC-12-0574-PAA-PU
Docket No. 120189-PU
Issued: October 24, 2012

Regulatory Liability Amount		$ (930,395.00)
Amortization Period:	Monthly	$ (27,365.00)
(34 Months)		

Exhibit NO. _____
DOCKET NO. 140025-EI
WITNESS: CHERYL M MARTIN
EXHIBIT NO. CMM-5
PAGE 1 OF 1

Income Statement-Amortization (4070)

HISTORIC YEAR

	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Total	MFR Schedule
As Booked		(301,015.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(574,665.00)	C-2
S/B Booked	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(328,380.00)	C-2
Historic Year ADJUSTMENT	(27,365.00)	273,650.00	-	-	-	-	-	-	-	-	-	-	246,285.00	C-2

PRIOR YEAR

	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Total	MFR Schedule
Amortization	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(328,380.00)	
Total Amortization	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(27,365.00)	(328,380.00)	C-2

PROJECTED TEST YEAR

	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	Total	MFR Schedule
Amortization	(27,365.00)	-	-	-	-	-	-	-	-	-	-	-	(27,365.00)	
Total Amortization	(27,365.00)	-	-	-	-	-	-	-	-	-	-	-	(27,365.00)	C-2, C-19

Regulatory Liability - Post Retirement Benefit
Order No. PSC-13-0594-PAA-PU
Docket No. 130185-PU

Exhibit NO. ____
DOCKET NO. 140025-EI
WITNESS: CHERYL M. MARTIN
EXHIBIT NO. CMM-6
PAGE 1 of 1

BALANCE SHEET

HISTORIC YEAR

Per Books	Sept 2012	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	**Sep 2013**	13-mo total	13 month avg.
Post Retirement Benefit				(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	**(258,659)**	(2,586,590)	**(198,968)**
Amortization Booked														-	-
Balance 2809-2540	-	-	-	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	**(258,659)**	(2,586,590)	**(198,968)**
Adjusted Balance Sheet															
Post Retirement Benefit	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	**(258,659)**	(3,362,567)	**(258,659)**
Amortization Ordered	68,468	76,076	83,684	91,290	98,898	106,506	114,114	121,722	129,330	136,938	144,546	152,154	159,760	1,483,486	**114,114**
	-	-	-	(167,369)	(159,761)	(152,153)	(144,545)	(136,937)	(129,329)	(121,721)	(114,113)	(106,505)	**(98,899)**	(1,879,081)	**(144,545)**
														Adjustment	**54,424**

PRIOR YEAR

Adjusted Balance Sheet	Sept 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	**Sep 2014**	13-mo total	13 month avg.
Post Retirement Benefit	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	**(258,659)**	(3,362,567)	**(258,659)**
Amortization Ordered	159,760	167,368	174,975	182,583	190,190	197,798	205,406	213,013	220,621	228,229	235,836	243,444	251,051	2,670,274	**205,406**
	(98,899)	(91,291)	(83,684)	(76,076)	(68,469)	(60,861)	(53,253)	(45,646)	(38,038)	(30,430)	(22,823)	(15,215)	**(7,608)**	(692,293)	**(53,253)**

PROJECTED TEST YEAR

Adjusted Balance Sheet	Sept 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	**Sep 2015**	13-mo total	13 month avg.
Post Retirement Benefit	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	(258,659)	**(258,659)**	(3,362,567)	**(258,659)**
Amortization Ordered	251,051	258,659	258,659	258,659	258,659	258,659	258,659	258,659	258,659	258,659	258,659	258,659	258,659	3,354,959	**258,074**
	(7,608)	-	-	-	-	-	-	-	-	-	-	-	-	(7,608)	**(585)**

INCOME STATEMENT

HISTORIC YEAR

	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	**13-mo total**
Amortization Expense per Books	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization Expense per Order	7,608	7,608	7,606	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,608	7,606	**91,292**
Adjustment													**91,292**

PRIOR YEAR

	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	**13-mo total**
Amortization Expense per Order	7,608	7,607	7,608	7,607	7,608	7,608	7,607	7,608	7,608	7,607	7,608	7,607	**91,291**

PROJECTED TEST YEAR

	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	**13-mo total**
Amortization Expense per Order	7,608	-	-	-	-	-	-	-	-	-	-	-	**7,608**

Florida Public Utilities Company
General Liability

Type	Period	Amount
Regulatory Asset-General Liability Claim	5 years	$ 250,000.00
Amortization	Annually	$ 50,000.00
	Monthly	$ 4,167.00
General Liability Reserve - Large Claims	5 years	250,000.00
	Annually	$ 50,000.00
	Monthly	$ 4,167.00
General Liability Reserve - Small Claims	Annually	20,000.00
	Monthly	1,666.00
	Total Annually	$ 120,000.00
	Total Monthly	$ 10,000.00

Exhibit NO._____
DOCKET NO. 140025-EI
WITNESS: CHERYL M MARTIN
EXHIBIT NO. CMM-7
PAGE 1 OF 1

Income Statement (9250):

HISTORIC YEAR

	Oct 2012	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Total	MFR Schedule
Total Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	C-7

PRIOR YEAR

	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Total	MFR Schedule
Accrual-Small Claims	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,674.00	20,000.00	
Amortization of Regulatory Asset	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,163.00	50,000.00	
Total Expense	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,833.00	5,837.00	70,000.00	C-7

PROJECTED TEST YEAR

	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	Total	MFR Schedule
Accrual-Small Claims	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,666.00	1,674.00	20,000.00	
Accrual-Large Claims	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,163.00	50,000.00	
Amortization of Regulatory Asset	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,167.00	4,163.00	50,000.00	
Total Expense	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	120,000.00	C-7

PTO PLAN (Paid Time Off)

All incumbent employees are offered an annual choice between two "time off" plans. All new non-union employees hired after December 31, 2006, or union employees hired after their respective union contract date within 2007, will be on the PTO Plan.

Every December incumbent employees are eligible to switch to the PTO plan, effective the following January 1st, of the following year. Once an employee has made a decision to participate in the PTO plan, they cannot switch back.

The first plan is the same vacation, personal days, and sick time plan that we currently have in effect, with no changes. The 8 holidays, plus the two personal days (i.e. floating holidays) will also remain unchanged, as will funeral leave and jury duty.

The second is a PTO (Paid Time Off) plan. With the PTO plan, employees are offered a specific number of PTO days per year in place of the current vacation, personal days, and sick time plans. The 8 major holidays that we have now remained unchanged and outside of PTO, as is funeral leave and jury duty. The two personal days (i.e. floating holidays) available in the first plan are included in the PTO days listed below. Employees earn a new allotment of PTO time every January 1st, and will be earned according to the below guideline:

a. 17 days after 1 year of service
b. 22 days after 5 years of service
c. 27 days after 15 years of service
d. 32 days after 25 years of service

PTO days can be used for any purpose, including caring for sick family members if needed. All PTO days need to be scheduled in advance with the employees immediate supervisor, with the exception of time needed due to legitimate illness or non work related injury of the employee or one of their family members, or if they have a personal hardship, either of which requires a call to the supervisor before the start of each work day. Department Managers will keep track of PTO time taken (tracked in hours) that are scheduled in advance (i.e. vacation and/or personal days) and unscheduled hours (sick time due to illness or injury). Department managers will have discretion to limit scheduling of PTO during peak season timeframes or to limit the number of employees off at any one time.

Unused PTO days, up to 5 days per year, are accumulated or "banked" for future years use. Up to 10 weeks of unused PTO, plus the unused portion of the current year's allotment, will be paid out at retirement or termination; however this pay-out will be excluded from pension benefit calculations.

Incumbent employees, selecting the PTO plan, will keep 100% of their existing sick time bank, which will be frozen at the time that they elect the PTO plan. This bank of sick time will be available for a legitimate illness or injury and not for vacation or personal time. If an employee needs time off for an illness or injury, they will be required to utilize a minimum of 5 PTO days first (if available) before using their sick time bank, and will require a doctor's note. Employees are able to utilize a maximum of 16 weeks of banked sick time in any one calendar year after first utilizing 5 PTO days, providing that they have a doctor's note to support the medical absence.

Employees must work on their scheduled workdays before and after a holiday in order to receive holiday pay unless they are on a) paid leave of absence, b) long term disability, c) scheduled PTO, or d) have a legitimate illness or injury with a doctor's note.

Loaning or donating PTO or banked sick time from one employee to another is prohibited.

When the employee's allotment of PTO days has been exhausted, they will not have any other paid time available for the balance of the year unless they have banked sick time to be used for a legitimate illness or injury. Generally, good attendance is required as part of each employee's job performance expectations, and the use of unpaid (i.e. no work – no pay) time off beyond the PTO allowance is not acceptable unless the employee has a personal hardship.

In general, employees will be limited to taking no more than 3 weeks off at a time for vacation or personal reasons. However, employees will be given a one-time-only opportunity to take 4-8 weeks off at one time if they have sufficient time available to them; have requested the time off with ample notice for the department to plan for this time off; and it fits within the business needs of the department and the Company.

PTO for new employees will be as per the below guideline:

New employees who start in the first quarter of a year receive:

a) 2 days after 90 days of service
b) 4 days on October 1 of the year of hire
c) 4 days on January 1 following the year of hire
d) 4 days on April 1 following the year of hire
e) 4 days on July 1 following the year of hire
f) 4 days on October 1 following the year of hire
g) 17 days on the following January, and every January 1 from that point forward, increasing with years of service as per the above guidelines.

New employees who start in the second quarter of a year receive:

a) 2 days after 90 days of service
b) 4 days on January 1 following the year of hire
c) 4 days on April 1 following the year of hire
d) 4 days on July 1 following the year of hire
e) 4 days on October 1 following the year of hire
f) 17 days on the following January, and every January 1 from that point forward, increasing with years of service as per the above guidelines.

New employees who start in the third quarter of a year receive:

a) 2 days after 90 days of service
b) 4 days on April 1 following the year of hire
c) 4 days on July 1 following the year of hire
d) 4 days on October 1 following the year of hire
e) 17 days on the following January, and every January 1 from that point forward, increasing with years of service as per the above guidelines.

New employees who start in the fourth quarter of a year receive:

a) 2 days after 90 days of service
b) 4 days on July 1 following the year of hire
c) 4 days on October 1 following the year of hire
d) 17 days on the following January, and every January 1 from that point forward, increasing with years of service as per the above guidelines.

FLORIDA PUBLIC UTILITIES
— energy for life —

Policy No.:	HR-2013-1
Effective Date:	January 1, 2014
Supersedes:	PTO Plan eff: 1/1/07
Approved by:	Devon Moormann

PAID TIME OFF

Paid Time Off (PTO) is a benefit provided to eligible Chesapeake and FPU employees. Employees accrue PTO based upon tenure with the Company and are able to use available PTO to schedule paid absences from work.

New employees who are eligible for benefits begin accruing PTO hours on their date of hire. However, new hires are not permitted to utilize their PTO time during the three-month introductory period of employment. PTO is paid out at the employee's regular rate of pay and cannot be carried over into the next year. Thus, unused PTO time will be lost if not taken. An exception will be made if the employee was unable to use accrued PTO because of business demands. In this case, the employee may request and receive a payout of 8-40 PTO hours with the approval of the Department Manager and the Human Resources Department.

PTO Requests

All requests for PTO from exempt or non-exempt employees must be approved by the Department Manager. Every effort will be made to accommodate employee requests, but the manager's first priority will be the needs of the department. In order to ensure appropriate coverage, managers may request a projected PTO plan from each employee in the department. Employees are strongly encouraged to schedule five (5) consecutive working days off each year.

PTO Accrual Schedule

Full-time employees accrue PTO hours each pay period based upon the employee's anniversary date. Part-time employees who are eligible for benefits accrue at pro-rated amounts. The accrual rates are determined as follows:

Years of Service	PTO Days Per Year
< 5 Years	14
5 - 14 Years	19
15 - 24 Years	24
Over 25 Years	29

*PTO balances appear each pay period on employee pay stubs.

PTO time advanced to the employee (prior to being accrued) must be repaid upon voluntary or involuntary separation from the Company. This balance will be deducted from the employee's final paycheck.

REDACTED

FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS

OF

P. MARK CUTSHAW

AND

DRANE A. (BUDDY) SHELLEY

Q. **Please state your name, affiliation, business address and summarize your professional experience and academic background.**

A. My name is P. Mark Cutshaw. I am the Director of System Planning and Engineering for Florida Public Utilities Company (FPU or Company). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPU in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. In January 2006, I became the General Manager of our Northeast Florida Division, and in 2013, I moved into my current position of Director of System Planning and Engineering. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. Most recently, I provided testimony in the Commission's Fuel and Purchased Power Cost Recovery Proceeding in 2013. I also testified in the Company's 2007 rate case in Docket No. 070304-EI as part of a panel with Don Myers. Likewise, I participated in the 2003 rate case filing (Docket No. 030438-EI), wherein the Commission authorized the

Company to consolidate the base rates of the Company's Northeast (Fernandina) and Northwest (Marianna) divisions. I have been involved with numerous other filings, audits and data requests before the FPSC, including filing testimony on several prior occasions in the Fuel and Purchased Power Cost Recovery proceeding, as well as the preparation and support of the Company's cost of service studies for the 1993 rate case (Docket 930400-EI) and presentation of the Company's storm hardening and hurricane preparedness activities.

Q. Are you familiar with the operations and management of the Northeast and Northwest Florida divisions?

A. Yes. Having worked directly in both divisions and now as the Director of System Planning and Engineering for the Company, I am very familiar with all aspects of the operations and management. I have also been responsible for collecting the information necessary to support this important part of our filing.

Q. **Please state your name, affiliation, business address and summarize your professional experience and academic background.**

A. My name is Drane A. (Buddy) Shelley. I am Director, Electric Operations for Florida Public Utilities Company (FPU). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPU in December, 2006 as Operations Manager in the Marianna (Northwest Florida) Division. In February, 2009, I was promoted to General Manager of the Northwest Florida Division, and in 2013, I moved into my current position of Director, Electric Operations. I graduated from Murray State University in 1976 with a B.S. in Electrical Engineering Technology and began my career with Big Rivers Electric

Company in May, 1976. I spent 15 years with Big Rivers Electric Company and held positions of increasing responsibility that involved substation, transmission, distribution and power plant electrical design, as well as operations and maintenance activities. After leaving Big Rivers, I worked 14 years for three (3) different Engineering Consultant Firms providing services to several Electric Utility Companies including IOU's, Municipals, and Cooperatives. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. No.

Q. Are you familiar with the operations and management of the Northeast and Northwest Florida divisions?

A. Yes. Having worked directly in both divisions and now as the Director, Electric Operations for the Company, I am very familiar with all aspects of the operations and management. I have also been responsible for collecting the information necessary to support this important part of our filing.

Q. What is the purpose of your panel testimony in this proceeding?

A. We will provide information in Section I relating to the important projects that our Company has implemented over the last four years in a successful effort to improve the reliability of our electric system. We will also explain the rationale behind these projects and support the appropriateness of the associated investment dollars and expenses to be included in new base rates. In that context, we will address our Pole Replacement Plan and our Storm Hardening Plan. We will also address in Section II several other capital projects undertaken by the Company in recent years but will focus on one particular critical project. These additional projects are designed to support customer growth, improve customer service and provide significant fuel savings for FPU's customers. We will discuss our new operations center in Section III and describe our purchase power partners in Section IV and explain how we are working to lower customer fuel clause expenses. In Sections V and VI, we will address the Company's proposed cost of service methodology, including certain changes that the Company is seeking in conjunction with this rate case filing; the Company's rate design methodology, including a proposed step rate increase, as well as the benefits of consolidation of the Company's fuel rates, which the Company intends to propose for further Commission consideration later this year in the context of the Commission's fuel cost recovery proceedings. Finally, in Section VII, we will describe some of the positive impacts that the acquisition by Chesapeake Utilities Corporation has had on the Company's ability to improve reliability, improve safety, and provide savings for customers.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. We have 9 exhibits. Exhibit MC/DS-1 is a list of the MFRs that we sponsor. Exhibit MC/DS-2 is a list of capital projects that relate to reliability improvement efforts. Exhibit MC/DS-3 is a copy of our 2013 Storm Hardening and Reliability Report. Exhibit MC/DS-4 is a compilation of metrics related to FPU electric system reliability. Exhibit MC/DS-5 is a list of on-going and projected capital projects. Exhibit MC/DS-6 is a compilation of safety statistics. Exhibit MC/DS-7 is a list of the proposed lighting rates to be included in this proceeding. Exhibit MC/DS-8 is the determination of the purchase power adjustment changes that will be required with the consolidation of the outdoor and street lighting rates. Finally, Exhibit MC/DS-9 will include information regarding the purchased power adjustment benefits that customers will receive based upon a proposed cogeneration project. We have reviewed and support the preparation of each of these exhibits.

Q. Are you sponsoring any MFRs in this case?

A. Yes. We are sponsoring the MFRs listed in Exhibit MC/DS-1. To the best of our knowledge, these MFRs are true and correct.

Q. Please describe who will be responsible for the different aspects of the testimony.

A. Yes. P. Mark Cutshaw will be the primary witness responsible for defending the majority of the testimony. Drane A. (Buddy) Shelley will provide additional support to the testimony with particular focus on the operations activities and construction work.

Q. Please describe FPU's distribution system and your service area.

A. The service area is divided into the Northeast and Northwest Florida Divisions with a total of just over 31,000 customers. The Northeast Florida Division is located in Nassau County with the service area being confined to Amelia Island. The Northwest Florida Division is located in portions of Jackson, Calhoun and Liberty Counties with the majority of the customer base being located in Jackson County.

Q. Would you describe FPUC's distribution system and service area for the two divisions as being similar?

A. No. The Northeast Florida division is located on Amelia Island with a total service territory of approximately 40 square miles. Customer density is very heavy with a similar mix of overhead and underground distribution facilities. The proximity to the beach and a large city helps stabilize the resort and vacation areas of the island while two large paper mills provide excellent job opportunities and additional stability to the area. While the economy did have an impact on this area the recovery seems to be making some progress.

The Northwest Florida division is located in a more rural, inland area with a total service territory of approximately 300 square miles. Customer density is relatively sparse, similar to what you would expect in a rural area, with the service provided predominantly by an overhead distribution system. The rural, more inland service territory with fewer industrial customers makes this area slightly more susceptible to economic downturns and is not showing the recovery being experienced in the Northeast Florida division.

Ia. CAPITAL PROJECTS RELATING TO RELIABILITY IMPROVEMENTS

Q. Please identify the various capital projects to which you have referred that relate to improving reliability on the FPU electric system.

A. The capital improvement projects relating to improving reliability can be categorized as follows: replacement of aging/unreliable underground conductors, replacement and upgrade of relay and control schemes at substations, replacement/upgrade of transmission circuit breakers at two substations, upgrade of a substation buss at one substation, replacement of wood distribution poles, relocation of distribution lines that had been inaccessible to roadways, replacement of insulators along a coastal highway, replacement/upgrade/addition of distribution voltage regulators/reclosers, and replacement of wood transmission poles with concrete poles. Since 2008, and through our projected test year, we have or will have spent in excess of $10,900,000 for reliability improvements.

A. <u>Replacement of Aging/Unreliable Underground Conductors</u>

Q. What did the projects to replace underground conductors entail?

A. In the Northeast Division there were a significant amount of underground conductors that had been installed in the 1970s. These conductors were aging poorly and needed to be replaced. The scope of these projects was to replace underground conductors on Amelia Island with a significant portion of the work being conducted on the south end of Amelia Island. The focus on the south end of the Island was due largely to construction activity that occurred in that area in the 1970's.

Q. What were the costs associated with these projects?

A. Over $4.6 million was spent through the end of 2013 with total projected costs through 2014 projected to reach over $5.0 million. Exhibit MC/DS-2 shows the projects and associated cost details.

Q. Why were these projects necessary?

A. The existing underground conductors were older technology conductors that were operated in a harsh environment, in areas where the groundwater was near the surface and the salt content was high. They had been installed directly in the ground with an exposed concentric neutral. The concentric neutral in many cases had deteriorated and there was pitting of the conductor insulation. The failure rates were extremely high, at one point occurring almost daily. Reliability was suffering and customers were being adversely impacted.

Q. What benefit has the Company seen as a result of these projects?

A. The Company has experienced a significant reduction in underground cable failures, which reduces outages, improves the reliability indicators and has a direct impact in the reduction in overtime work and associated expense. Details of this type of improvement are included in the Company's annual 2013 Storm Hardening and Reliability Report that was submitted March 1, 2014 a summary of which is included in Exhibit MC/DS-3.

Q. What benefits have customers seen as a result of these projects?

A. Customers have benefitted from improved reliability through reduced electric outages which had significant, unwanted impacts on the daily life of our customers. Exhibit MC/DS-4 shows the detail and trend of FPU reliability metrics.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. As previously indicated, the Company was experiencing very frequent outages in certain areas prior to these projects to replace underground conductors. There was no other way to effectively remedy the situation and further delay would have exacerbated the deteriorating situation. Replacement of the underground cable in these areas actually began around 2000 and was focused on small areas of replacement each year. The cable failures and resulting outages, however, quickly outpaced the rate of cable replacement, which was ultimately accelerated slightly in 2006. This replacement effort continued, but the outages nonetheless continued at an unacceptable level. After the merger, our new parent, Chesapeake Utilities recognized that more focus should be applied to improving reliability. As a result, the decision was made to further accelerate the cable replacement with a goal to complete the work in 2013. Although some work still remains, the majority of the work was completed by year end 2013, and the outage rate has decreased dramatically as a result.

B. Replacement and Upgrades of Relays and Control Schemes at Substations

Q. What did the projects to replace and upgrade relays and control schemes at substations entail?

A. These projects primarily involved replacing existing electromechanical relays with electronic digital relays in multiple substations.

Q. What were the costs associated with these projects?

A. The costs were approximately $430,000. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. The Northeast Florida division does not currently have a Supervisory Control and Data Acquisition (SCADA) System and must rely on manual control of the substations. In order to move towards the installation of a functioning SCADA system and to comply with certain North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council (FRCC) compliance standards, the project began the systematic replacement of electromechanical relays within the substations with electronic digital relays. The relays could be easily integrated into a SCADA system, could also be programmed to comply with NERC/FRCC compliance standards and have also proved to be much more reliable than previous relays.

Q. What benefit has the Company seen as a result of these projects?

A. In addition to compliance with NERC and FRCC requirements, the Company will see two areas of benefits. First, replacing the older technology allows for more reliable and more secure substation operation. But also very importantly, the new electronic digital relays afford the opportunity for more flexible control schemes and the ability to remotely control operations and obtain additional information regarding the status and operational history of the substation.

Q. What benefits have customers seen as a result of these projects?

A. These projects have contributed to the improvements in the Company's reliability measures as shown on Exhibit MC/DS-4 and will continue to provide improvement as SCADA system controls are added.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. These projects were necessary both for regulatory compliance and as an integral part of the Company's reliability improvement plan.

C. <u>Replacement/Upgrade of Transmission Circuit Breakers at Two Substations</u>

Q. What did the projects to replace transmission circuit breakers at the referenced two substations entail?

A. Both the Amelia Island Plantation Substation and the Step-down Substation housed 1970's vintage switchgear which was becoming a recurring source of maintenance issues, was an older technology and had reached the end of its useful life. These projects focused on the replacement of the circuit breakers in the substations with modern equipment and the necessary modifications to the buss configuration necessary to maximize the effectiveness of the installation.

Q. What were the costs associated with these projects?

A. The costs were approximately $300,000 at the Amelia Island Plantation Substation and $1.09 million at the Step-down Substation. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. As stated, this switchgear was old and deteriorating. In particular, with regard to the circuit breakers, the insulators were breaking down, and the hydraulic systems were wearing out which would eventually lead to breaker failures and slow systems operations. In addition, the configuration of the buss only marginally met NESC code clearance requirements and could have been dramatically impacted by wind borne debris during a hurricane.

Q. What benefit has the Company seen as a result of these projects?

A. The main benefit to the Company is to improve the overall reliability and safety of the electric system by replacing outdated equipment with new technology equipment. The newer equipment operates much more quickly and reliably and avoids the possibility of mis-operations or catastrophic failure.

Q. What benefits have customers seen as a result of these projects?

A. In general customers are benefitting from the overall improvements to reliability on the FPU system. In particular, if one of these older breakers had failed while in service, there would be the high likelihood of a prolonged outage to the segment of population being served. Additionally, some of the breakers use mineral oil as the insulating medium which could have resulted in environmental issues should a failure occur.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. Any delay would have increased the risk of long interruptions of service to customers and possible penalties for failure to maintain equipment up to code.

D. Upgrade of a Substation Buss at one Substation

Q. What did the projects to upgrade the substation buss entail?

A. These projects consisted of several activities at the Company's Amelia Island Plantation substation, the largest element of which was the replacement and re-insulation of the substation main buss. In conjunction with the replacement and re-insulation of the buss, the Company replaced a roof and purchased additional property around the substation for future reconfiguring the equipment.

Q. What were the costs associated with these projects?

A. Total project costs were about $800,000. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. The Amelia Island Plantation substation is located next to a water treatment plant and near the Atlantic Ocean, which results in a very corrosive environment. The 12.47 KV portion of the substation is metal enclosed switchgear. However, the enclosure/building has not provided adequate protection from the environment. As it was, the roof over the switchgear was problematic because there was no opportunity for rain to wash chemicals and particulates off the enclosed insulators and buss. This raised the likelihood of a flashover and subsequent catastrophic outage. Upon preparing to perform an initial test on the system, FPU determined, prior to the upgrade, that even testing the insulators and buss was unsafe due to the visible deterioration of the equipment. The replacement and re-insulation of the buss therefore significantly reduced the risks of equipment failure.

Q. What benefit has the Company seen as a result of these projects?

A. There have been no flashovers or equipment failures and the new equipment has extended the life of the substation. The purchase of the additional property has also provided easy access to the substation and will allow additional modifications to the substation as needed in the future due to capacity increases or further modifications in substation design. The additional property purchase also resolved a long time issue related to access rights to the substation by eliminating the need to cross private property to access the substation.

Q. What benefits have customers seen as a result of these projects?

A. Customers have not experienced outages due to failure of this equipment and have enjoyed overall better reliability because of this and other reliability enhancement projects.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. As with other projects discussed, any delay would have increased the risks of extended outages to customers and the possibility of a significant substation failure and posed a serious safety concern for FPU employees required to maintain and operate the switchgear.

E. Replacement of Wood Distribution Poles

Q. What did the distribution pole replacement project entail?

A. The Company has employed Osmose to perform extensive testing of its wood distribution pole system. This project, as of year-end of 2013, consists of the inspection of approximately 3,000 poles each year which has resulted in the inspection of a total of 21,235 (81.2%) poles since the beginning of the program in 2008. The inspection results have identified a total of 1,745 poles that required replacement. Of that number, 888 have already been replaced with 857 remaining to be replaced. The exact cost associated with the replacement of these poles is not available, but we estimate it to be approximately $1,800,000. Previous results indicate that approximately 600 additional poles will be identified as requiring replacement during the 2014 and 2015 inspection cycles. The total cost to replace the 857 pole backlog, along with the 600 additional poles we anticipate will be identified for replacement, will be approximately $2,900,000 over the next few years. This will complete the initial eight (8) year inspection cycle.

Q. Is this a component of your approved Storm Hardening Plan?

A. Yes, it is.

Q. What were the costs associated with this project?

A. The costs for pole replacement over the life of the project are anticipated to be approximately $4,700,000, which equates to approximately $580,000 per year.

Q. Why was this project necessary?

A. Damaged or rotted wooden poles are among the first casualties of weather related events. As part of the Storm Hardening Plan, the testing program and associated replacement of wood poles have demonstrated that it is imperative to replace decayed wooden poles on a regular basis.

Q. What benefit has the Company seen as a result of this project?

A. The Company is in compliance with its Storm Hardening Plan as approved by the Commission. In addition, unusual increases in operations and maintenance expenses should be avoided in future years as more of the decayed/weaker poles are identified and replaced.

Q. What benefit have customers seen as a result of this project?

A. Customers have enjoyed overall better reliability due to this and other projects described here, as well as a reduced risk of outages during significant weather events..

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have increased the risk of outages and hurt the reliability of the system. Furthermore, the Company would not have been in compliance with the Commission Storm Hardening requirements.

F. Replacement of Wood Transmission Poles

Q. What did the project to replace wood transmission poles entail?

A. This project entailed the replacement of 34 wood poles with concrete poles.

Q. Is this a component of your approved Storm Hardening Plan?

A. Yes, it is.

Q. What were the costs associated with this project?

A. The costs are anticipated to be approximately $1.4 million.

Q. Why was this project necessary?

A. A detailed inspection in 2013 of the FPU 138 KV and 69 KV transmission systems found that 34 of our 69 KV wood transmission poles needed to be replaced due to severe woodpecker damage or the decayed/rotted condition of the pole with the major cause of the damage to poles being woodpecker damage. These poles are critical to the integrity of the transmission system on the island.

Q. What benefit has the Company seen as a result of this project?

A. In addition to complying with our Commission-approved Storm Hardening Plan, the replacement of these wood poles with concrete poles should avoid any unusual increases in operations and maintenance expense in future years.

Q. What benefit have customers seen as a result of this project?

A. Customers will experience improved reliability as a result of this and other reliability enhancement projects.

Q. Could the company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would result in increased risks to customers.

G. <u>Relocation of Distribution Lines</u>

Q. What did the project to relocate inaccessible lines entail?

A. This project included relocating/rebuilding several lines and line segments from wooded rural areas to roadways primarily in the Northwest Division.

Q. What were the costs associated with this project?

A. The costs were approximately $495,000.

Q. Why was this project necessary?

A. In the Northwest Division, there are numerous distribution lines located in wooded areas that are difficult or impossible to reach by vehicle. Part of the Company's Storm Hardening Plan is to place facilities on public rights-of-way and/or easements. This project was important to reliability and necessary to comply with our plan.

Q. What benefit has the Company seen as a result of this project?

A. Relocating these distribution lines to roadways has provided several benefits: employees can monitor and assess the condition of these lines in a more efficient manner; when there is maintenance to be performed or repairs/restoration to be accomplished the employees and truck-mounted equipment can be placed right at the work location; and safety is enhanced because employees aren't walking through woods at night during a storm to locate and physically climb poles to repair/restore service.

Q. What benefits have customers seen as a result of this project?

A. As with our other projects, reliability has been improved as a result of relocating these lines out of areas subject to vegetation issues to areas that are better maintained and more accessible. Outages are less frequent and of shorter duration.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. This issue was another source of repair and maintenance issues, which contributed further to our reliability issues. Reliability has now been enhanced because of this and other projects the Company has undertaken.

H. Replacement of Insulators along a Coastal Highway

Q. What did the project to replace insulators at locations along the referenced coastal highway entail?

A. The Company has overhead electric distribution facilities that are constructed along the coastal highway designated as A1A which extends down the east side of Amelia Island bordering the Atlantic Ocean. This project consisted of replacing insulators on this wooden pole line.

Q. Does the location of this equipment in close proximity to the coast necessitate more frequent or extensive maintenance and replacement?

A. Yes. The presence of fog and salt spray off the ocean create a corrosive environment. The buildup of salt and other particulates on insulators increase the likelihood of a flashover during foggy conditions which results in an outage.

Q. What were the costs associated with this project?

A. The costs were approximately $290,000.

Q. Why was this project necessary?

A. In addition to the corrosive environment common to all coastal areas, this is an older line with dated technology porcelain insulators. When cracks or chips occur on the glazing of the insulators, there is a higher likelihood of contamination that can cause a flashover and the resulting failure of the insulator. The replacement insulators employ newer technology insulators made of a rubber/silicone material that is more impervious to the damaging effects of the sun and salt environment.

Q. What benefit has the Company seen as a result of this project?

A. The Company should not experience an unusual increases or spikes in maintenance expense along this line in the future.

Q. What benefit have customers seen as a result of this project?

A. The customers will see fewer outages as a result of this and other reliability enhancement projects.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have increased the risk of faults/outages and therefore interruptions to customer service.

I. <u>Replacement/upgrade of Distribution Regulators/Reclosers</u>

Q. What did the project to replace regulators and reclosers entail?

A. Voltage regulators and reclosers along several distribution feeders and in certain substations in the Northwest Florida (Marianna) Division area were replaced.

Q. What were the costs associated with this project?

A. The costs were approximately $300,000.

Q. Why was this project necessary?

A. The Northwest Division is relatively rural in nature and has relatively long feeders. The voltage regulators are needed to regulate voltage along these lines and the reclosers serve to sectionalize the feeders as a critical part of the distribution system and are widely deployed in the area. Since some of the equipment has been in service for a number of years, the equipment was experiencing operational glitches and overt failures, was no longer reliable and had reached the end of its useful life; therefore, the replacement was critical. The Company needed to replace this equipment promptly to maintain proper voltage levels, as well as safe and reliable service to its customers.

Q. What benefit has the Company and its customers seen as a result of this project?

A. As with the other projects discussed, reliability is the most significant benefit. We were receiving numerous customer complaints about low voltage levels on some of the more heavily loaded feeders in the NW system which led to problems with proper appliance and equipment operation. The replacement of the old voltage regulators has dramatically reduced these complaints. The replacement and addition of new, digitally controlled reclosers has allowed us to better isolate and restore customer outages quicker. The

Company should not experience an unusual increase in operating and maintenance expense as a result of this replacement project.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have resulted in increased the risks of service interruptions, as well as prolonged interruptions, and continued voltage level complaints from customers.

J. <u>Ongoing and Planned Capital Projects Relating to Reliability Improvement</u>

Q. What additional projects relating to reliability are ongoing and planned to be completed in 2014/2015?

A. These projects include: additional distribution wooden pole replacements based on the 8-year replacement cycle established by the testing program, additional transmission wooden pole replacements, replacement of a large 40,000 kilovolt-ampere (kVA) substation transformer, upgrades of two distribution feeders, continued replacement of old voltage regulators, addition of reclosers and upgrading the transmission and substation system for improved reliability and in preparation for a planned additional cogeneration project. One of the two distribution feeder upgrades is required by the Company's Storm Hardening Plan, namely the upgrading of the feeder to a hospital in Marianna.

Q. What are the costs associated with these projects?

A. Total project costs for this category are expected to be approximately $9,145,500 for 2014 and 2015. Details of the projects with descriptions and individual project costs are shown on Exhibit MC/DS-5.

Q. Why are these projects necessary?

A. All of these projects are necessary to continue the improvement in reliability that our customers are now experiencing. The completion of these projects will lower the risk of outages, facilitate the inspection and testing of power lines/equipment, expedite the maintenance and repair of power lines and related equipment, allow for quicker and more effective restoration operations when outages do occur and provide access to additional purchased power that will be less expensive and more reliable that is currently available.

Q. What benefits do the Company expect to see as a result of these projects?

A. The Company will experience more efficient operations, continue to storm harden the distribution and transmission electric systems and should avoid large increases in maintenance expense in future years.

Q. What benefit should customers expect to see as a result of these projects?

A. The customer will realize continued improved reliability, both in terms of number and duration of interruptions as a result of additional storm hardening of the electric system. Customers should also realize a reduction in the overall rate of electricity as a result of these projects.

Q. Could the Company have deferred these projects without risk to its level of service and service reliability?

A. No. These projects are critical to maintaining and improving service levels for our customers.

Q. Were all of the reliability projects you have addressed part of the Company plan?

A. Yes. These projects were part of a comprehensive planning process directed towards materially improving the Company's service reliability and ensuring ongoing compliance with our Storm Hardening Plan.

Q. Were your efforts successful and beneficial to your customers?

A. Yes, in all respects. As explained later in this testimony, overall measures of service reliability have improved as a result of our attention to these areas. Moreover, the Company not only adheres to its Storm Hardening Plan, which was most recently approved by this Commission in Docket No. 130131-EI, but also endeavors to stay abreast of the latest methods, technologies, and engineering advancements to further enhance reliability and harden FPU's system against storm damage with the goal of further improving our ability to provide reliable service to our customers.

Q. How did the Company conclude that these projects were needed?

A. Many of the projects were identified and completed based on maintenance and inspection activities that have been conducted both on a routine basis, as well as part of our

Storm Hardening Plan. Examples of these include: review of reliability indicators, pole inspections, underground system inspections, substation inspections, vegetation management activities and input from employees and customers.

Q. Why does the Company engage in maintenance and inspection activities?

A. First of all, it has always been the Company's goal to maintain its system consistent with industry safety and operating standards and in such a way that interruptions of service to customers are minimized. Our employees strive, and have been successful, at operating a safe and reliable electric system. However, the hurricanes of 2004 and 2005, which impacted most of Florida, resulted in lengthy outages for millions of electric customers. Throughout Florida, storm restoration costs were much higher than ever experienced. In particular, on the FPU electric system, 2004 brought Hurricanes Bonnie, Charley, Frances, Ivan and Jeanne and 2005 brought impacts from Hurricane/Tropical Storms Arlene and Dennis. Although each storm impacted FPU's system differently, each resulted in damage to the electrical systems and customer outages. From that experience, we gained valuable information and lessons were learned. In particular, we determined that, as a Company, there were three areas that we needed to address in order to make sure FPU was better prepared for any future such events, those areas being: (1) the frequency of facility inspections; (2) the testing of physical transmission and distribution assets; and (3) implementation of a more proactive approach overall to protection of our electric system. Having addressed those areas of concern, FPU now has a robust maintenance and inspection plan, which encompasses its approved Storm Hardening Plan, and expects to continue its successful efforts to improve reliability through projects such as these.

Q. How do customers benefit from these activities?

A. As you can see, the importance of reliability is a recurring theme of our testimony. That is largely because it is a very important part of customer satisfaction. Outages and service interruptions can be much more than just a minor inconvenience for our customers. They can, in fact, create numerous issues for customers, ranging from food spoilage to loss of critical business functions to traffic problems and similar safety concerns. A well-maintained electric system providing consistently reliable service not only lessens the inconveniences associated with service interruptions, but also better protects the business interests and safety of our customers and our employees.

Q. Have you been able to document service improvements to your customers?

A. Yes, we have. As shown on Exhibit MC/DS-4 to our testimony, FPU has made dramatic improvements in reliability since 2009. The Customer Average Interruption Duration Index (CAIDI) improved from 108.81 in 2009 to 93.31 in 2013. The System Average Interruption Duration Index (SAIDI) improved from 218.40 in 2009 to 169.66 in 2013. The System Average Interruption Frequency Index (SAIFI) improved from 2.01 in 2009 to 1.82 in 2013. Finally, the L-Bar Index, which measures the Average Length of Service Interruption, improved from 116.74 in 2009 to 91.97 in 2013.

Ib OPERATING AND MAINTENANCE EXPENSES

Q. Has the Company reviewed operating and maintenance expenses to ensure all the prudent and justified.

A. Yes. Shortly after the merger with Chesapeake in 2009, the new management team began a thorough review of internal business organizations throughout FPU. The new team set out to establish better defined goals and to ensure those goals were being met.

Q. What types of reviews were conducted and what changes occurred?

A. During this review, areas such as improved safety, customer service, system reliability and employee efficiency were the underlying goals. Safety and training functions were expanded, which provided employees with additional training and also increased the visibility of safety personnel in the daily work. During the review of the customer service area, the Company quickly determined that the systems and personnel in place at that time were not providing the level of customer service that was required. Changes were implemented to upgrade the systems used for customer service, and personnel were expanded to increase the level of customer service. Also, system reliability was well below a reasonable standard and had to be addressed. Operation and maintenance procedures were evaluated to ensure that items, such as wood pole testing, underground distribution inspections, vegetation management activities, transmission system inspections, infrared inspections, and the like, were sufficient. Based on the reliability indices, it was apparent that all these needed to be increased if improvement was to be achieved. Another major area that needed to be addressed involved employees and how their work environment and resources impacted their overall productivity and efficiency. During this review, areas such as personal protective equipment, office and vehicle conditions, access to materials, and related issues were addressed to provide employees with an environment that was conducive to increased efficiency and productivity.

Q. What benefits have the Company seen as a result of these changes?

A. Safety results have been improving, customer service measures have indicated an overall improvement, our electric system reliability indices are improving, and overall, our employees are much more engaged and productive. Additionally, through the management team's focus and increased engagement of all employees, the Company has reviewed cost to ensure increases occurred only when prudent and justified. This also allowed the consolidation of certain positions and functions within the operations group which has contributed to offsetting some of the cost increases related to improved customer service, enhanced safety measures and other costs outside of the Company's control.

II. CAPITAL PROJECTS NOT SPECIFICALLY RELATED TO RELIABILITY IMPROVEMENTS

Q. What other capital projects have been executed since the Company's last test year?

A. In addition to reliability improvement projects, the Company has invested significant amounts in projects to improve our Company's operations and provide better customer service. These projects fall into several categories including: supporting customer growth that may occur, facilitating new generation supply, installing a new customer information system, replacement of general plant items and routine maintenance of the electric system.

Q. Please describe the most significant project in the category of increasing capacity to serve new growth?

A. We are engaged in an ongoing project to construct a new underground distribution feeder to serve areas where customer growth is anticipated in the near future. This feeder will provide a needed distribution tie between two substations for backup supply during emergency conditions or routine maintenance. This project involves the installation of approximately four (4) miles of distribution lines and associated distribution equipment.

Q. What are the projected costs associated with this project?

A. Total project costs are expected to be approximately $1,200,000 when the job is completed in 2015.

Q. Why are projects such as this necessary?

A. The Company has an obligation and a desire to serve all customers. There are however, areas in the Northeast and the Northwest Divisions where existing feeders will not accommodate the service requirements associated with new customers on our system. Therefore, in order to serve new customers in these areas, we much undertake this and similar such projects. Otherwise, we will be unable to meet our service obligations.

Q. What benefit does the Company expect to see as a result of these projects?

A. The Company will meet its obligations to serve new customers and realize a larger customer base on which to spread its fixed costs. Also, these projects will continue to provide more reliability to the systems and provide redundancy in areas in which it does not currently exist.

Q. What benefit should customers expect to see as a result of these projects?

A. New customers will receive reliable electric service that they expect and all customers should benefit from a larger energy usage base among which fixed costs will be spread.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. New customers will not be served if assets are not added.

III. OPERATIONS CENTER

Q. Has the Company implemented other improvements that have had an impact on operations?

A. Yes. In 2013, the Company opened a new operations center in Fernandina Beach, which serves as the headquarters for the Northeast Division.

Q. What prompted the decision to open the new operations center?

A. Prior to 2013, operations in the Northeast Division was split between an office facility (engineering, customer service, planning) at 911 S. 8th Street and a warehouse facility (construction, maintenance, warehouse) located at 611 Lime Street. The office facility was built in the 1970's and was insufficient to efficiently serve customers and employees. The warehouse was constructed in the 1940's and had deteriorated significantly over the years. The warehouse site had originally housed a generation facility for the island, as well as, an ice plant for its customers.

Q. What are the benefits to Company operations derived from the new operations center?

A. Combining the office, operations and warehousing groups into the new location is more efficient and promotes better communications among employees. Additionally, the old warehouse facility has significant structural issues and did not provide an environment that was conducive for employees comfort and well being. Moreover, the small multi-level facility was very difficult to move around in safely and efficiently.

Q. What are the direct benefits to customers of this new operations center?

A. In addition to more seamless customer service resulting from better employee communications, the new operations center is much more centrally located to the customers in the Northeast Division. As such, it provides easier access for customers, including an expanded parking area, as well as a conveniently located drop box that can be accessed by customers from their vehicles.

IV. PURCHASED POWER PARTNERS

Q. Does the Company own and operate any generation assets?

A. No, not at this time.

Q. Does the Company therefore purchase power from other entities in order to serve the two electric divisions?

A. Yes. For the Northwest Division, FPU purchases power from Gulf Power Company under a Commission-approved purchased power agreement. For the Northeast Division, the

Company is currently under contract with JEA for power supply, but also has contracts with certain Federal Energy Regulatory Commission ("FERC") certified "qualifying facilities" for additional power purchases. The additional power purchases are at costs less than the JEA contract prices which in turn provide a savings to customers.

A. Savings for the Northwest Division

Q. When did the Company enter into its contract with Gulf Power Company for power for the Northwest Division?

A. Dating back to the 1960's, the Northwest Florida division purchased its all requirements wholesale power from Gulf Power Company. Numerous contracts were executed through the years. Effective January 1, 1997, an eleven year agreement became effective that would continue through December 31, 2007. During the course of the contract, purchase power costs were very favorable and resulted in FPU having some of the lowest electric rates in the State of Florida. In 2006, as its then-current purchased power contract approached expiration, FPU again selected Gulf Power for a new ten-year power supply agreement to begin January 1, 2008. Implementation of that new contract was, from a customer relations perspective, very complex, because the expiring contract had been negotiated at a time when costs related to the provision of electric energy were relatively stable. As such, the expiring contract had included firm prices for the provision of electric service which incorporated transmission service in that firm price. The new contract that became effective in 2008 includes market-based costs, with environmental costs rolled into the energy costs. Under the new arrangement, transmission services have been separated out and are provided, and priced, under a separate contract with Southern Company Services.

The 2008 contract with Gulf Power was approved by the Commission in Docket No. 070108-EI, wherein the Commission acknowledged the Company's representations that Gulf Power has proven to be a good business partner, provides reliable service, and that the new contract was the best, most cost-effective offer available to FPU. The new contract did, however, result in a notable price increase to customers in the Northwest Division. The Company undertook significant efforts, including public relations and customer education campaigns, as well as regulatory proposals for rate consolidation and graduated increase, in an effort to lessen the initial impact to customers. Nonetheless, the impact of the new agreement for many FPU customers was hard felt, particularly because it was implemented during the early stages of the country's economic downturn.

As the economic downturn continued, FPU looked for ways to provide relief to its customers in both divisions. At different points between 2008 and 2009, FPU engaged in some limited conversations with Gulf Power about the possibility of adjusting the contract in some way that would provide benefits for both parties.

Q. How did the 2011 Amendment to the purchase power agreement with Gulf Power Company come about?

A. Subsequent to the Commission's approval of the 2008 contract with Gulf, the Company entered into a new franchise agreement with the City of Marianna. A notable component of the new franchise required the Company to implement Time of Use (TOU) rates and Interruptible rates by February 17, 2011.

Not long after the Company entered into the new franchise agreement, specifically October 28, 2009, Chesapeake Utilities Corporation and Florida Public Utilities Company consummated the transaction whereby Florida Public Utilities Company became a wholly-owned subsidiary of Chesapeake.

After the acquisition by Chesapeake, FPU, now under new management, began the process of reviewing and determining how best to develop and implement the TOU and Interruptible rates mandated by the Franchise. FPU quickly determined that, in order to develop TOU and Interruptible rates that would satisfy the requirements of the Franchise and also comply with Commission regulatory requirements, changes to the 2008 contract with Gulf would be necessary. Thus, the Company actively engaged Gulf in discussions to develop a negotiated Amendment that would provide FPU with the pricing flexibility necessary to develop TOU and Interruptible rates that are cost-based and otherwise in compliance with regulatory requirements. As a result, the companies reached an agreement reflected by Amendment No. 1 to the 2008 contract.

Q. Has the Amendment No. 1 proven to be beneficial?

A. Yes. The Amendment has proven very beneficial to FPU and its rate payers. Specifically, the Amendment provides, on average, annual savings of $900,000 for FPU's customers in the Northwest Division over the life of the contract by reducing the fuel and purchased power charge for FPU customers.

B. <u>New Renewable and Cogeneration Contracts</u>

Q. Has the Company investigated means to reduce costs for its customers in the Northeast Division as well?

A. Yes. The Company has aggressively sought opportunities to engage its current base load provider for the Northeast Division in discussions for an arrangement that would be more beneficial for the FPU customers. Since 2007, when purchased power rates began to increase significantly from JEA, FPU has been very assertive in challenging each cost of service study performed by JEA that resulted in an increase to the purchased power rate. These very focused and steady efforts have resulted in the mitigation of the rate of increase in purchased power cost for FPU and its customers. These same focused and steady efforts are continuing today and, in our opinion, have resulted in a reduced rate of increase to FPU and its customers.

During this same time period, the Company has investigated opportunities with other wholesale power suppliers. During the investigation relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed and contract possibilities were discussed. Although these opportunities are not possible until the expiration of the JEA contract, this information does provide FPU with market knowledge and information that assist with discussions with JEA.

Also, the Northeast Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities which has created opportunities for some limited purchased power for FPU. Based on this potential, FPU has entered into arrangements with these alternative power providers that have thus far proven very advantageous. FPU is continuing to look at these and all other avenues for reducing purchased power costs that are available to the Company.

Q. What type of investigation has the Company done related to reduction of purchased power cost?

A. Since the merger with Chesapeake in 2009, the Company has focused many resources on how to reduce the purchased power cost and its impact on customers. As previously mentioned, during this time other wholesale power providers have been approached and opportunities explored, review of new electric generation technology has been conducted, Combined Heat and Power (CHP) partners have been identified, experts in the area of CHP projects have been retained and parties have come together to evaluate electric generation projects. These partners and experts have assisted FPU with the review and evaluation process. Ultimately, most of the projects evaluated were not prudent ventures for the Company. However, the Company's review team found that certain limited projects, one partner in particular, are viable alternative power options for the Company and provide benefits to the partners and customers. FPU is continuing to evaluate this type of opportunity both inside and outside of the FPU service territory.

Q. To what arrangements with "alternative power providers" do you refer?

A. The first very successful arrangement that I am referring to is the renewable energy contract with Rayonier Performance Fibers, LLC, which was entered into in early 2012 and approved by the Commission in Docket No. 120058-EQ. Through a cooperative effort, FPU and Rayonier were able to develop a purchased power agreement that allows Rayonier to produce renewable energy and sell that energy to FPU at a cost below that of the current wholesale power provided while still being beneficial to Rayonier. Not only did this increase the amount of renewable energy in the area, it provides lower cost energy that is passed directly through to FPU customers in the form of reduced power cost.

Secondly, FPU is also working in partnership with [redacted] Eight Flags Energy, LLC, a subsidiary of Chesapeake Utilities Corporation (Chesapeake), [redacted] The details of the arrangement are currently being finalized and we anticipate filing with the Commission in the very near future. [redacted] will provide customers with a significant benefit in the reduction of purchase power cost. This detail of this benefit is included in Confidential Exhibit MC/DS-9.

Q. How have these two new arrangements proven beneficial to the Company?

A. With regard to the first contract with Rayonier, that agreement alone is expected to produce overall savings of $1.27 million over the 10-year term of the contract, and the Company has every expectation that the contract will be extended, thereby extending the benefits. The expected annual energy produced will be 16,980 mWh's and an incentive is provided to Rayonier to ensure this occurs in that any failure to maintain the agreed capacity factor will result in reducing the overall monthly payments to Rayonier.

[redacted] efforts are underway to get this completed, approved and in service by the first quarter of 2016. Once consummated and in service, this new project is expected to produce even more significant benefits for the Company and its customers. [redacted]

[redacted]

V. COST OF SERVICE

Q. Why is a cost of service study necessary?

A. It is necessary to analyze the costs to serve each rate class in order to fully analyze the Company's revenues and appropriately determine the allocation of contributions made by the various rate classes. Generally, in a cost of service study, costs are typically allocated to the rate classes according to the cost to serve each class. The results are, therefore, useful in helping to determine: (a) whether a rate increase is appropriate; and (b) what rate changes are necessary.

Q. Is FPU's cost of service study in this case consistent with the methodology used in past cases?

A. Yes. Certainly, there are other methods for allocating costs, but the methodology that FPU is proposing in this proceeding provides a fair and equitable allocation of costs to the rate classes, is accurate, and has been accepted by the Commission for FPU in other proceedings.

Q. Please describe the fully-allocated cost of service study that was used to determine this interclass revenue allocation.

A. The method used in this proceeding follows previous rate proceedings filed by FPU. The method used to allocate our costs closely follows the long-held ratemaking principles and practices for cost apportionment as specified in the "Electric Utility Cost Allocation Manual" developed by the National Associations of Regulatory Utility Commissioners (NARUC) in January 1992. Once the relevant data on rate base and net operating income are compiled, as the Company has done in Scheduled A-D, these costs are apportioned to customer classes through a three step process called functionalization, classification and allocation. I will describe these steps:

Functionalization: The costs are identified by the function they perform or, another way of looking at it, the service provided. FPU provides three services: transmission, distribution and customer services. Since FPU purchases all of its power from a third party and delivers it to the customer, there is no production service provided by the Company.

Classification: The costs identified for each function are classified based on the manner in which costs vary, i.e. costs will change by changes in the component of utility service provided. The three (standard) cost classifications used by FPU are demand related (costs vary by KW load); energy related (costs vary by kWh's used); and customer related (costs that are directly related to the number of customers using the service). Transmission services are treated predominantly as demand-related cost. Distribution services are separated into demand, energy and customer related. And, customer services are either demand related or customer related.

Allocation: Once the costs are functionalized and classified, they must be allocated to the different customer classes. This is done using allocation factors for each of the cost classification categories. The allocation factors used in the FPU study are listed and described in MFR Schedule E-13. As a summary, transmission costs are allocated according to the coincident peak plus $1/13^{th}$ demand factor (a weighted combination of contribution to the system peak and the average hourly demand of the class). Distribution demand costs are allocated according to each class' non-coincident peak demands. Customer costs are allocated by the number of customers and by a weighting of the specified customer-related cost, e.g. meter expense.

Q. Please explain how FPU determined the increase in review by class.

A. Our fundamental ratemaking objective is to apportion revenue recovery responsibility and design rates to reflect, to the maximum extent practicable, the cost of serving each customer and customer class. In order to determine the cost responsibility we used the results of a fully-allocated embedded cost of service study conducted on the consolidated division service by FPU as provided in MFR Schedule E-1. A comparison of rates of return by class for present rates is provided in Schedule E-3 along with the percentage increase in base rates required for each class to recover the target rate of return. It is our understanding that long-held Commission policy provides that the percentage rate increase for each class must be no more than 1.5 times the system average increase and that no rate class should receive a decrease in rates. Based on the results of the Cost of Service study, the RS, GS, GSD, GSLD GSLD1, SB, Outdoor Lighting and Street Lighting were found to match the parity percentages, as much as practical, that were accepted for FPU during the Company's last rate proceeding while still achieving the targeted return.

Q. What increase in rates was indicated for each of the class of customers served by FPU based on the cost of service results?

A. The total base rate revenue recovered from each of the customer classes and the total revenue impact on each rate class on a percentage basis is shown below:

Class	Base Rate Increase %	Total Rate Increase %
Residential	30.5%	7.0%
General Service	39.7%	10.6%
General Service Demand	49.1%	7.2%

General Service Large Demand	47.6%	5.1%
General Service Large Demand 1	55.9%	6.5%
Outdoor Lighting	17.3%	12.6%
Street Lighting	26.8%	19.3%

Q. Please explain what the differences are between direct and indirect costs.

A. Direct costs can be related to labor, transportation, materials, and the like that are specifically used and identified as related to a specific type of expense or project. Indirect cost can be the same types of costs but are allocated to specific types of expense or project by pre-determined allocation methodologies.

Q. Please describe the load data used to derive the class coincident and non-coincident demands used in the cost of service study.

A. FPU is too small to have its own load research program; therefore, we rely on the load research data collected by Gulf Power Company (Gulf). Gulf provided data for 2003, 2006 and 2010-2011 which was translated to billing determinants and load based cost of service allocators for the 2015 test year.

Q. Please describe any special studies performed and how they relate to the allocation methods you described above.

A. In order to allocate certain costs, a study was performed on distribution plant as it related to poles, conductors/conduit/devices, meters, outdoor lights and street lights. The poles and conductor/conduit/devices were evaluated to determine the appropriate contribution to either the primary or secondary distribution systems. Meters were evaluated to determine the appropriate contribution to each rate class. Customer lights and Street lights were evaluated to determine the appropriate contribution to each class. These factors were then used as a basis for allocating costs.

Q. Please describe the results of your cost of service study.

A. The initial results were analyzed to ensure that no rate class received an increase greater than a 1.5 times the system average and no rate class received a decrease. Adjustments were made to ensure compliance with these requirements and any difference in the revenue requirement was then allocated back to the other rate classes with each rate adjusted accordingly to provide for the target revenue return. Final percent increases were then determined. Every effort was made to ensure that the analysis was consistent with that employed in our last rate case proceeding and that the results achieved an appropriate level of parity across the rate classes.

Q. Please explain why you believe the cost of service methodology for allocating costs is most appropriate for FPU?

A. This methodology has been utilized for our prior rate proceedings and has resulted in excellent results. Data has been provided that works well with this methodology and once again seems to have provided excellent results.

VI. RATE DESIGN

Q. After you determined the interclass revenue allocation, how did you design

rates to achieve the revenue requirement?

A. The results of the cost of service study shown in Schedule E-1 include unitized costs for the customer and demand and energy charges within each specified class of service. We unitized these costs to adjust the pricing components within each class to the maximum degree possible.

Q. Have you restructured any rates?

A. Yes we have. The Residential Class rate (RS) and the Lighting Class rates (OL and SL) have been restructured and will be described below.

Q. Please describe the rate design changes for the Residential Class.

A. The current Residential (RS) rate consists of a $12.00 per month customer charge with a $0.01958 per kWh energy charge. To this we applied the percentage increase for the residential class and included a step rate in the energy charge to determine the new rates. The new Residential rate will now consist of a $16.00 per month customer charge with an energy charge of $0.02170 per kWh for usage less than or equal to 1,000 kWh per month and an energy charge of $0.03420 per kWh for usage above 1,000 kWh per month.

Q. Please describe the rate design changes for the General Service Non-Demand Class.

A. The current General Service Non-Demand (GS) rate consists of an $18.00 per month customer charge with a $0.01927 per kWh energy charge. To this we applied the percentage increase for the General Service Non-Demand class to determine the new rates. The new

General Service rate will now consist of a $24.00 per month customer charge with an energy charge of $0.02582 per kWh. The Sports Field rate in this class will be eliminated and customers will be transitioned to the new GS rate.

Q. Please describe the rate design changes for the General Service Demand Class.

A. The current General Service Demand (GSD) rate consists of a $52.00 per month customer charge with a $0.00340 per kWh energy charge and a $2.80 per KW demand charge. To this we applied the percentage increase for the General Service Demand class to determine the new rates. The new General Service Demand rate will now consist of a $65.00 per month customer charge with an energy charge of $0.00571 per kWh and demand charge of $4.20 per KW.

Q. Please describe the rate design changes for the General Service Large Demand Class.

A. The current General Service Large Demand (GSLD) rate consists of a $100.00 per month customer charge with a $0.00145 per kWh energy charge and a $4.00 per KW demand charge. To this we applied the percentage increase for the General Service Large Demand class to determine the new rates. The new General Service Large Demand rate will now consist of a $150.00 per month customer charge with an energy charge of $0.00218 per kWh and demand charge of $6.00 per KW.

Q. Please describe the rate design changes for the General Service Demand Large 1 Class.

A. The current General Service Large Demand 1 (GSLD1) rate consists of a $600.00 per month customer charge with a $0.00000 per kWh energy charge, a $1.12 per KW demand charge and a $0.24 per excess kilovolt-amperes reactive, or kVAR, demand charge. To this we applied the percentage increase for the General Service Large Demand 1 class to determine the new rates. The new General Service Large Demand 1 rate will now consist of a $900.00 per month customer charge with an energy charge of $0.00000 per kWh, a demand charge of $1.68 per KW and a $0.36 per excess KVAR charge.

Q. Please describe the rate design changes for the Standby Rate Class.

A. The current Standby rate (SB) rate consists of a $626.47 per month customer charge with a $0.00000 per kWh energy charge and a $0.53 per KW demand charge. To this we applied the percentage increase for the General Service Large Demand 1 class to determine the new rates. The new Standby rate will now consist of a $940.00 per month customer charge with an energy charge of $0.00000 per kWh and a demand charge of $0.80 per KW.

Q. Please describe the rate design changes for the Street Lighting and Outdoor Lighting Classes.

A. Within the COS model, we incorporated our intention to combine all lighting into one Lighting Rate Schedule. Standard allocation procedures were followed to determine the new revenue requirement for all lighting. The percentage impact for specific lights can be found within the E Schedules while proposed rates for lights can be found in Exhibit MC/DS-7. The existing SL and OL rate schedules have been deleted and they have been combined into a new Lighting Service (LS) rate schedule. For the existing mercury vapor lights, which are no longer available for new installations we created the Outdoor and

Street Lighting (OSL) rate schedule. As a result of the combination of these rate schedules, there will also be a change in the Rate Adjustment Rider for each division. The OL and SL purchased power factor will be consolidated to align with the combined LS and OSL rate schedules which will result in new fuel clause recovery amounts and rates for lighting in both divisions. The details and calculations of these proposed modifications are included in Exhibit MC/DS-8

Q. Please describe why you are proposing to combine the Street and Outdoor lighting rate classes.

A. Street Lighting and Outdoor Lighting are managed from the same types of materials using the same types of labor and transportation to install and maintain these lights. In reality, very little if any, difference should be apparent through the cost of service study results. However, the results do come out slightly different due to a long standing effort to keep these types of lights separate and the margin of error through years of COS modeling. Combining these rate classes will result in more equitable rates for lighting customers.

Q. Are you proposing any changes to the Service Charges in this filing?

A. Yes. The proposed service charges are provided in MFR Schedule E-7. Each service charge was evaluated in order to determine the appropriate cost and revenue requirement for each. Labor cost, transportation costs and overheads were applied to the typical task associated with each service charge. Based on typical costs, service charge amounts were determined for six different tasks.

A service charge for the initial establishment of service was set at $61.00, as compared to the existing amount of $53.00. A service charge for making changes to or reestablishing an existing account was set at $26.00, as compared to the existing amount of $23.00. A service charge to temporarily disconnect and then reconnect a service due to customer request was set at $65.00. The existing amount is $33.00. This increase was due to a change in the classification of personnel who will be involved with this type of work activity. A service charge to reconnect a service after a rule violation was set at $52.00 during normal business hours and $178.00 after normal business hours, as compared to the existing amount of $44.00 during normal business hours and $95.00 after normal business hours. A service charge used for connecting a temporary service was set at $85.00, as compared to the existing amount of $52.00. A service charge used during collection activities in the field was set at $16.00, as compared to the existing amount of $14.00.

When a customer requests that a new temporary service be installed and later removed a service charge was set in the amount of $230.00 for an overhead service and $200.00 for an underground service, as compared to the existing amount of $200.00 for an overhead service and $170.00 for an underground service. Should a pole be required in order to install the temporary service an additional service charge was set at $395.00 per pole for an overhead service and $560.00 per pole for an underground service, as compared to the existing amount of $200.00 per pole for overhead or underground services.

Q. Are you proposing any changes to the Transformer Ownership Discount?

A. No.

Q. Why are you proposing to include a step rate within the Residential rate class?

A. As has been thoroughly described in the current step rate included in the residential purchased power adjustment rate approved by the Commission in Order No. PSC-08-0030-FOF-EI, there are numerous benefits to the Residential rate class and the general body of rate payers based on this type of step rate. A very significant factor is the conservation benefit that this affords. Consumers are financially benefitted to conserve electricity and minimize usage below 1,000 kWh per month. As more customers are incented to this benefit, the overall system usage will be reduced which should translate into improved load factors and reduced purchased power cost. This will, in turn, directly benefit all rate payers through reduced charges. The step rate differential proposed in the base rate is equivalent to the amount currently included in the fuel adjustment.

Q. Are you proposing any changes to the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") or Time of Use Rates?

A. With the exception of the change associated with lighting rates which was mentioned above, there are no other changes at this time. However, FPU may seek approval to consolidate its 2015 fuel rates within the Fuel Clause filing in September 2014, which is consistent with the Commission's directive to the Company in the 2013 Fuel Clause proceeding, in Order No. 13-0665-FOF-EI. If approved, this will result in a single fuel factor for all FPU customers that will provide long term benefits for all rate payers through, among other things, a reduction in existing inequitable subsidization across our service territories. The TOU rates, which are based on our fuel costs, will also be impacted within the consolidation of fuel rates.

Q. Are you proposing any additional changes to the rates?

A. Yes. We will be adding an Economic Development Rider Program (EDRP) to the rates.

Q. What benefits will this EDRP provide to customer?

A. This program is intended to work along with local economic development organizations to attract additional business to the community which brings additional jobs and opportunities to the community. The participants will be required to have a minimum electrical load of 200 KW in order to take advantage of the discounted electrical rate. The program discount begins with a 20% reduction in base energy and demand charges in the applicable rate which decreases annually by 5% with the discount expiring in the fifth year. More detailed information regarding this rate is included in Testimony provided by Company Witness Aleida Socarras.

VII. IMPACT ON OPERATIONS OF ACQUISITION BY CHESAPEAKE

Q. With regard to the acquisition of FPU by Chesapeake Utilities Corporation, have there been additional benefits as it relates to FPU's electric system?

A. Yes. There have been meaningful improvements that have proven beneficial to the Company, its customers, as well as its employees. Specifically, prior to its acquisition by

Chesapeake, FPU was a relatively small operation in Florida with an overtaxed leadership team that was mainly focused on day-to-day tactical matters. On the electric side of the Company, there was insufficient attention and inadequate resources devoted to critical areas including system reliability, safety, purchased power costs, customer service and relationships with cities and towns that were being served. Upon the closing of the acquisition, Chesapeake immediately implemented initiatives to make improvements and upgrades to these and other areas. Although these efforts have resulted in some necessary increases in administrative and general expenses, they have much improved the electric utility, both for customers, as well as employees.

A. Investment in Improving System Reliability

Q. What specific improvement initiatives did Chesapeake undertake for FPU?

A. Historically, the FPU electric system had suffered from the poorest reliability statistics in the state of Florida. The frequency of outages on the FPU electric system was unsatisfactory. Likewise, the duration of outages on the FPU electric system was also unsatisfactory. Chesapeake responded by promptly installing a new executive leadership team in Florida, which initiated an assessment/review of what improvements needed to be made to the electric system to improve reliability. The executive team concluded it was necessary to take the following actions:

1. Bring in more experienced personnel in operations;
2. Add a safety coordinator in each of the electric divisions as described elsewhere in this testimony;

3. Replace the old warehouse facility on Amelia Island, as described elsewhere in this testimony, and upgrade the Marianna facility including painting, parking lot drainage and office remodeling. This greatly improved employee morale and has provided a greatly enhanced sense of pride about the Company and the physical systems;

4. Develop new training facilities in both electric divisions that include poles, transformers, switches, fuses and reclosers. This training has improved and enhanced the ability for climbing poles, working in buckets, rewiring transformers, switching and service work for restores;

5. Replace and upgrade tools and other equipment. One example is the replacement of manual tools to battery operated. This had greatly improved the speed and consistency of our linemen's work;

6. Implement online NERC compliance training, which has increased the thoroughness and consistency of training while decreasing the time away from field work;

7. Develop a formalized program of maintenance and capital investment; and

8. Increase involvement and input from the corporate headquarters, which has been important to this overall effort to improve our system.

As I have noted earlier in my testimony, these efforts have been successful. Reliability has improved overall as measured by SAIDI/CAIDI/SAIFI/L-Bar, complaints have been reduced, and FPU now compares more favorably with other electric utilities in the region.

B. Implementing a Safety Culture

Q. What other initiatives have been implemented by Chesapeake that benefit the Company's operations?

A. Prior to the acquisition, FPU promoted safety but had not ingrained it into the culture of the organization from top to bottom. Chesapeake Utilities, in contrast, has always placed the greatest importance on safety of its employees, its customers and the general public. In fact, Chesapeake Utilities has won numerous awards for its safety achievements. Chesapeake's new executive leadership team in Florida instituted an assessment of what needed to be done in Florida to instill a true culture of safety in FPU. These efforts included a Company-wide program called Service Excellence, which leads off with Company values regarding safety: (1) resolving safety issues and concerns first, (2) being proactive in creating a safe work and community environment, (3) honoring all safety regulations and procedures and (4) always wearing personal protective equipment. In addition, the following actions were taken:

1. We created a Safety and Training Coordinator position for each division to provide ready access for employees to safety and job related training;
2. We conducted multiple monthly safety meetings in each facility to ensure access for all employees to current and pertinent safety information;
3. We required FPU Safety coordinators to obtain certification in CPR/First Aid and OSHA 30 Hour General Industry in order to provide training to all employees;

4. We revised our Lineman Apprentice Training program to ensure adequate training and opportunities to promote apprentices to journeymen linemen;
5. We built training yards in our electric divisions to train apprentices and to provide climbing and pole top rescue training;
6. We began a daily Stretching and Flexibility program for all linemen to prevent sprains and strains and improve balance;
7. We initiated "Smith System" defensive driving for all employees to promote better driving habits and reduce accident potential;
8. We began providing monthly refresher training in job specific duties for all linemen;
9. We researched and acquired upgraded personal protective equipment and flame retardant uniform options; and
10. We instituted safety incentive programs to recognize safe employee behavior and promote culture of awareness.

Q. Have these efforts been successful?

A. Yes. These efforts have been enormously successful. FPU has indeed adopted a true safety culture and the results have been significant. In the vehicle accident area, incidents have declined slightly since 2011 while mileage has increased, resulting in a 25% reduction in the accident rate, from a rate of about 4 to a rate of about 3. The results in the Recordable Injury rate are even more impressive. The Incident Rate has decline from over 10.1 to about

1.7, an improvement of 83%. Detailed year by year statistics are available as shown on Exhibit MC/DS-5.

C. Additional Benefits to Operations

Q. Are there other areas where the Chesapeake acquisition has had a positive impact on FPU's electric division?

A. Yes. As it relates to the operations side of the business, in particular, the more proactive corporate philosophy has provided significant benefits in a couple of key areas – power purchases, as I have discussed, and franchise relationships.

[redacted]

Q. What changes did Chesapeake initiate to improve FPU's franchise management and relationships?

A. Prior to the acquisition by Chesapeake, FPU had inadequate administrative resources to appropriately manage franchise relationships with the cities and towns to which it provided electricity. For instance, in the Northwest division, the City of Marianna initiated efforts to purchase the franchise from FPU and provide the service to its own citizens. The resulting dispute, including court filings, involved a significant amount of time and effort being spent by FPU to retain the franchise. The time was, however, well-spent, in that negotiations with the City ultimately produced a settlement and the franchise was retained. If this sort of issue were to become an ongoing occurrence, it would be costly to customers and unduly distracting to Company personnel. Consequently, Chesapeake has directed the implementation of proactive initiatives to avoid, or at least limit, this situation in the future. These actions include:

1. Attending council meetings and building relationships with the cities and towns we serve;
2. Working closely with regional economic development organizations, chambers of commerce and trade organizations; and
3. Becoming involved in the communities we serve.

In other testimony in this case, Company Witness Aleida Soccaras provides more detail about our Community Involvement and related efforts.

Q. Please summarize your testimony.

A. In order to enhance customer service, FPU and its parent, Chesapeake, have invested significant amounts of time and resources over the last several years in a wide array of projects designed to improve reliability levels. The investment has been successful, resulting in improvement in the Company's overall reliability measures between 2009 and 2013 and further anticipated improvement in the future. These expenditures and other planned expenditures were, and will continue to be, well-planned, efficiently executed, and should be allowed for cost recovery in this proceeding. Never before in the history of FPU has such significant investment in system infrastructure occurred and never before has such an improvement in overall system reliability occurred. FPU is committed to maintaining the electrical systems by investing as necessary now and into the future.

As investment increases, so does the need to adjust electric rates accordingly. However, FPU is also committed to being proactive in working to keep overall electric rates at a reasonable level for FPU customers. In the Cost of Service study completed in conjunction with this proceeding, all cost items included have been subjected to intense scrutiny and are considered prudent by the Company. As such, we ask that the Commission reach the same conclusion and deem these costs justified for recovery through base rates. In our COS, we used standard methodologies throughout the analysis in order to fairly and reasonably allocate costs to the different rate classes and likewise determine appropriate rates. This method has been successfully used in previous filings and is consistent with Commission-defined parameters. With the exception of the consolidation of lighting rates, elimination of the sports field rate, addition of the residential step rate, and the addition of the Economic Development Program Rider, the overall rate structure remains the same. While rates are increased based upon the results of the COS, our methodology is not new. In sum, the proposed rates are fair and equitable for the customers of FPU and reflective of a fair allocation methodology that incorporates prudent costs and justifiable expenditures.

Currently, purchased power cost accounts for more than 70% of our customers' total bill. FPU is therefore committed to continuing to aggressively work to mitigate any increases, and potentially decrease, it's purchased power costs in the future. FPU, along with resources from Chesapeake, are prepared to continue to focus on ensuring fair and equitable rates for customers, improving system reliability, fostering a safety culture that benefits employees and customers, and continuing to improve relationships within our communities in which we work and serve.

Q. Does this conclude your testimony?

A. Yes.

Exhibit ______

MC/DS-1

MFR'S Sponsored by Mark Cutshaw

MFR Number	**Title**
A-2	Full Revenue Requirements Bill Comparison-Typical Monthly Bills
A-3	Summary of Tariffs
A-5	Interim Revenue Requirements Bill Comparison-Typical Monthly Bills
C-34	Statistical Information
E-1	Cost of Service Studies
E-2	Explanation of Variations from Cost of Service Study Approved in
E-5	Source and Amount of Revenues-At Present and Proposed Rates
E-6a	Cost of Service Study-Rates fo Return by Rate Schedule (Present Rates)
E-6b	Cost of Service Study-Rates fo Return by Rate Schedule (Proposed Rates)
E-7	Development of Service Charges
E-8	Company-Proposed Allocation of the Rate Increase by Rate Class
E-9	Cost of Service-Load Data
E-10	Cost of Service Study-Development of Allocation Factors
E-11	Development of Coincident and Non-coincident Demands for Cost Study
E-12	Adjustment to Test Year Unbilled Revenue
E-13a	Revenues From Sale of Electricity by Rate Schedule
E-13b	Revenues by Rate Schedule-Service Charges (Account 451)
E-13c	Base Revenue by Rate Schedule-Calculations
E-13d	Revenue by Rate Schedule-Lighting Schedule Calculation
E-14	Proposed Tariff Sheet and Support for Charges
E-15	Projectd Billing Determinants-Derivation
E-16	Customers by Voltage Level
E-17	Load Research Data
E-18	Monthly Peaks
E-19a	Demand and Energy Losses
E-19b	Energy Losses
E-19c	Demand Losses
F-5	Forcasting Models
F-6	Forcasting Models-Sensitivity of Output to Changes in Input Data
F-7	Forcasting Models-Historical Data
F-9	Public Notice
G-20	Interim-RevenueForm Sale of Electicity by Rate Schedule
G-21	Interim-Revenues From Service Charges (Account 451)
G-22	Interim-Base Revenue by Rate Schedule Calculations
G-23	Interim-Base Revenue by Rate Schedule Calculations

project # Pre-CHPK	Account Group	Project Name	Start Date	Reliability	Total	Underground Cable Replacement In NE Florida	Relay and Control Scheme Upgrades	Substation Circuit Breaker Upgrades	Upgrade of Substation Buss	Distribution Wood Pole Replacement	OH Line Upgrades and Relocate Line to Accessible Location	Coastal Highway Upgrade	Replacement of Reclosers and Regulators	Transmission Line Upgrades	Substation Transformer Replacement
22267	3672	UG Cable at AIP	Pre-2009	yes	$243,747	$ 243,747									
22235	362	UFLS Relays at AIP	Pre-2009	yes	$65,911		$ 65,911								
22398	3672	UG at AIP	Pre-2009	yes	$214,075	$ 214,075									
22226	3683	7 Amelia Island -Replace UG	Pre-2009	yes	$119	$ 119									
22109	3693	Beachwood S/D-AIP	Pre-2009	yes	$1,113	$ 1,113									
22226	3657	7 Amelia Island -Replace UG	Pre-2009	yes	$1,581	$ 1,581									
22226	3647	7 Amelia Island -Replace UG	Pre-2009	yes	$1,652	$ 1,652									
22209	356	Insulators on CKT 315	Pre-2009	yes	$12,133									$ 12,133	
22109	3672	Beachwood S/D-AIP	Pre-2009	yes	$115,567	$ 115,567									
22109	3662	Beachwood S/D-AIP	Pre-2009	yes	$228,055	$ 228,055									
21922	3622	Transformer for AIP Substation	Pre-2009	yes	$838,152										$ 838,152
2433	362	Purchase & install vacuum breaker	Pre-2009	yes	$32,748				$ 32,748						
2431	365E	Reclosure 1-11 Feeder	01/01/09	yes	$30,994								$ 30,994		
2398	366E	Beachwalker II	01/01/09	yes	$214,722	$ 214,722									
2324	365E	Fletcher Trans Poles	01/01/09	yes	$49,566									$ 49,566	
2324	356E	Fletcher Trans Poles	01/01/09	yes	$151,354									$ 151,354	
2324	355C	S. Fletcher Ave Poles	01/01/09	yes	$296,670									$ 296,670	
blanket	364E	Decayed Pole Repl	01/01/10	yes	$48,719					$ 48,719					
2482	353E	138 kV Diff Relays	01/20/10	yes	$86,499		$ 86,499								
blanket	364E	Poles Decayed Repl	01/27/10	yes	$104,354					$ 104,354					
2489	367E	Marsh Creek	02/05/10	yes	$120,218	$ 120,218									
2489	366E	March Creek Area 2	02/05/10	yes	$193,985	$ 193,985									
2501	365E	OH Circuir Recloser	03/09/10	yes	$40,697								$ 40,697		
2520	364E	REPLACE DECAYED POLES	04/26/10	yes	$105,164					$ 105,164					
2520	365E	Decayed Poles & Conductors	04/28/10	yes	$8,517					$ 8,517					
2566	365E	Hwy 162 relocation of line	07/16/10	yes	$7,283						$ 7,283				
2566	364E	Hwy 162 relocation of line	07/16/10	yes	$7,996						$ 7,996				
2601	367E	REPLACE failed URD	09/08/10	yes	$23,280	$ 23,280									
2601	366E	REPLACE failed URD	10/04/10	yes	$646	$ 646									
2628	353E	Rplc 69KV Relays-SD Sub	10/19/10	yes	$152,727		$ 152,727								
2634	365E	Pearidge Rd.	10/20/10	yes	$4,497						$ 4,497				
2634	364E	Pearidge Rd.	10/20/10	yes	$10,202						$ 10,202				
2685	355C	Conc. Pole-Ins Issue	12/17/10	yes	$19,365									$ 19,365	
	365E	S FLETCHER REINSULATE	01/01/11	yes	$32,837							$ 32,837			
	364E	POLES DISTR - NE BLKT	01/01/11	yes	$142,326					$ 142,326					
	353E	REPLACE DAMAGED 69KV PT	02/01/11	yes	$5,495	$ 5,495									
	365E	SPARE RECLOSER	03/02/11	yes	$17,991								$ 17,991		
	362E	AIP RELAY REPLACE	04/25/11	yes	$144,758			$ 144,758							
	365E	PRIMARY OLD KNAPP, ETC	05/05/11	yes	$26,566						$ 26,566				
	364E	PRIMARY OLD KNAPP, ETC	05/05/11	yes	$29,876						$ 29,876				
	362E	2011 Reg Control Purch	05/25/11	yes	$31,359								$ 31,359		
	362E	2011 Regulator Purch	05/25/11	yes	$49,605								$ 49,605		
	355W	RR 69KV Cond	06/06/11	yes	$66,682									$ 66,682	
	367E	Sea Marsh Area Cable	07/11/11	yes	$127,889	$ 127,889									
	366E	Sea Marsh Conduit	07/11/11	yes	$201,320	$ 201,320									
	367E	Repl Porcelain Term	08/01/11	yes	$55,996							$ 55,996			
	353E	two 69kV Circuit Swit	10/01/11	yes	$158,357			$ 158,357							
	367E	Marsh Cove Subdiv Cable	11/30/11	yes	$3,895	$ 3,895									
	366E	4811 Amelia Isl Conduit	11/30/11	yes	$7,056	$ 7,056									
	366E	Marsh Cove Subdiv Conduit	11/30/11	yes	$7,594	$ 7,594									
	367E	Stepdwn subfeeder exit cable	01/01/12	yes	$48,535	$ 48,535									
	365E	Osmose Pole Repl- insulators	01/01/12	yes	$76,053					$ 76,053					
	364E	Osmose Pole Repl approx 18	01/01/12	yes	$115,811					$ 115,811					
	365E	Reins Fletch Ave inst	01/01/12	yes	$193,883							$ 193,883			
	366E	Sea marsh area 6 conduit	01/01/12	yes	$281,127	$ 281,127									
	364E	PURCH (2) REG PLATFORMS	01/17/12	yes	$8,353								$ 8,353		
	367E	Sea Marsh area6 Ph1	02/20/12	yes	$257,555	$ 257,555									
	366E	Joint Trench Feeder 312-Ph 1	03/15/12	yes	$329,278	$ 329,278									
	366E	Amelia Plaza -conduit	03/19/12	yes	$4,457	$ 4,457									
	356E	Replace 69kv Insulator-#74	04/03/12	yes	$790									$ 790	
	353E	Rplce 4-69kv oil circuit brkrs	05/01/12	yes	$327,529			$ 327,529							
	367E	Amelia by the Sea -conduct	06/01/12	yes	$6,232	$ 6,232									
	366E	Amelia by the Sea - Conduit	06/01/12	yes	$6,810	$ 6,810									
	368B	AIP Office Complex	06/01/12	yes	$7,195	$ 7,195									
	367E	PEPPERTREE VILLAGE	06/01/12	yes	$29,253	$ 29,253									
	366E	PEPPERTREE VILLAGE	06/01/12	yes	$29,847	$ 29,847									
	367E	AIP Office Complex	06/01/12	yes	$32,031	$ 32,031									
	366E	AIP Office Complex	06/01/12	yes	$35,601	$ 35,601									

project # Pre-CHPK	Account Group	Project Name	Start Date	Reliability	Total	Underground Cable Replacement in NE Florida	Relay and Control Scheme Upgrades	Substation Circuit Breaker Upgrades	Upgrade of Substation Buss	Distribution Wood Pole Replacement	OH Line Upgrades and Relocate Line to Accessible Location	Coastal Highway Upgrade	Replacement of Reclosers and Regulators	Transmission Line Upgrades	Substation Transformer Replacement
	366E	Joint Trench Feeder 312-Ph 2	06/01/12	yes	$316,410	$ 316,410									
	353E	Stpdwn sub 69kv recon	06/08/12	yes	$615,099			$ 615,099							
	368B	AIP conf exp-inst txfmrs	06/11/12	yes	$9,905	$ 9,905									
	368B	SEA MARSH AREA 7	06/11/12	yes	$10,920	$ 10,920									
	367E	AIP conf exp-install Cable	06/11/12	yes	$70,843	$ 70,843									
	367E	SEA MARSH AREA 7	06/13/12	yes	$261,132	$ 261,132									
	366E	SEA MARSH AREA 7	06/20/12	yes	$326,149	$ 326,149									
	365E	OCR Purch and Install	07/26/12	yes	$27,172								$ 27,172		
	362E	Reg Purch and install	07/26/12	yes	$50,894								$ 50,894		
	353E	PTs at JTL Substation	08/01/12	yes	$109,208		$ 109,208								
	366E	Amelia Park Conduit	08/20/12	yes	$18,195	$ 18,195									
	367E	Amelia Park Cable	08/20/12	yes	$20,706	$ 20,706									
	356E	Repair CKT 315 69kv insul	08/23/12	yes	$1,551									$ 1,551	
	356E	REPLACE 31 WOOD TRANS POLES	09/01/12	yes	$20,151									$ 20,151	
	355C	REPLACE 31 WOOD TRANS POLES	09/01/12	yes	$378,823									$ 378,823	
	367E	Rplc 750MCM Cable-circ 104	10/01/12	yes	$161,401	$ 161,401									
	362E	Reinsulate AIP Sub 15kv	10/01/12	yes	$450,216				$ 450,216						
	356E	Replace 69Kv Arrestors	10/15/12	yes	$51,154									$ 51,154	
	3890	Land Purch for AIP Sub	11/14/12	yes	$320,005				$ 320,005						
	353E	Rplc 2 GCBs at Stpdwn Sub	12/01/12	yes	$145,567			$ 145,567							
	366E	OSMOSE POLE REPLACEMENT	01/14/13	yes	$294					$ 294					
	368H	OSMOSE RPLC - OH TXNS	01/14/13	yes	$3,842					$ 3,842					
	367E	OSMOSE POLE REPLACEMENT	01/14/13	yes	$4,786					$ 4,786					
	365E	OSMOSE POLE REPLACEMENT	01/14/13	yes	$13,366					$ 13,366					
	367E	RPLC 750MCM CBL	01/31/13	yes	$107,175	$ 107,175									
	365E	SWITCH CHANGE OUTS	02/01/13	yes	$6,972							$ 6,972			
	368H	REGULATOR PURCHASE	02/01/13	yes	$48,241								$ 48,241		
	367E	Install UG Cable CKT 312	02/01/13	yes	$378,043	$ 378,043									
	368H	AMELIA ROAD UPGRADE PH1	03/01/13	yes	$19,041						$ 19,041				
	366E	Upgrd UG Secondary S12th	03/01/13	yes	$33,678	$ 33,678									
	367E	Upgr UG Scdry S12th conduct	03/01/13	yes	$42,370	$ 42,370									
	365E	AMELIA ROAD UPGRADE PH1	03/01/13	yes	$66,631						$ 66,631				
	364E	AMELIA ROAD UPGRADE PH1	03/01/13	yes	$70,052						$ 70,052				
	366E	Repl TC95 to TC67	05/06/13	yes	$14,580	$ 14,580									
	368B	Gateway to Amelia Phase 1 Up	07/01/13	yes	$4,499	$ 4,499									
	362E	AIP Batteries Charger Repl	07/01/13	yes	$18,346		$ 18,346								
	367E	Gateway to Amelia Ph 1 Upgrd	07/01/13	yes	$19,970	$ 19,970									
	366E	Gateway to Amelia Phase 1 Up	07/01/13	yes	$39,117	$ 39,117									
	356E	Replace 69kv insulator	08/06/13	yes	$11,733									$ 11,733	
	365E	Line Relocation	08/21/13	yes	$19,274						$ 19,274				
	364E	Line Relocation	08/21/13	yes	$55,001						$ 55,001				
	355C	69kv Line Relo to Rayonier	08/30/13	yes	$50,792									$ 50,792	
	365E	System Upgrade Phase 1	10/01/13	yes	$83,861						$ 83,861				
	364E	System Upgrade Ph 1	10/01/13	yes	$94,528						$ 94,528				
	365E	repl 34 Transmission Poles	10/14/13	yes	$1,783									$ 1,783	
	355C	Repl 34 Transmission Poles	10/14/13	yes	$4,861									$ 4,861	
	356E	Repl 34 Transmission Poles	10/14/13	yes	$6,987									$ 6,987	
	362E	Purch Substation Equip-Mar	11/05/13	yes	$251								$ 251		
					$ 10,917,824	$ 4,615,021	$ 432,692	$ 1,391,311	$ 802,970	$ 623,232	$ 494,808	$ 289,687	$ 305,557	$ 1,124,395	$ 838,152

FLORIDA PUBLIC
UTILITIES

P.O. Box 418
Fernandina Beach
FL 32035-0418
Phone: 904/261-3663
Fax: 904/261-3666
www.fpuc.com

March 1, 2014

Mr. Thomas Ballinger, Director
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0868

Dear Mr. Ballinger:

Attached is Florida Public Utilities Company's required 2013 Annual Update. The update includes the Annual Distribution Service Reliability Report required by Rule 25-6.0455, the Annual Wood Pole Inspection Report required by Order No. PSC-06-0144, and updates of our Storm Hardening Plan and Ten Storm Preparedness Initiatives, as required by Order No. PSC-06-0781.

If you have any questions, please call 904-277-1957 or e-mail mcutshaw@fpuc.com .

Sincerely,

P. Mark Cutshaw

P. Mark Cutshaw
General Manager, NE Florida Division
Florida Public Utilities Company

Attachments
Cc:
Grant, William
Householder, Jeff
Martin Cheryl
Puentes, Jorge
Shelley, Buddy
Tanner, Lynwood
Toole, Steve
Webber, Kevin

Florida Public Utilities Company

Reliability, Wood Pole Inspections, Storm Hardening Plan, and Storm Preparedness Initiatives

2013 Annual Update

March 1, 2014

FLORIDA PUBLIC UTILITIES

Florida Public Utilities Company

**Reliability, Wood Pole Inspections,
Storm Hardening, and Storm Preparedness Initiatives**

Annual Update

Table of Contents

Introduction

Rule 25-6.0342, FAC, "Electric Infrastructure Storm Hardening, requires each investor-owned electric utility to file a comprehensive storm hardening plan for review and approval by the Florida Public Service Commission (FPSC). Florida Public Utilities Company (FPUC) submitted its Storm Hardening Plan to the Commission on 7/3/07. Docket No. 070300-EI was opened to address FPUC's filing (Storm Plan Docket). During 2010, FPUC submitted an update to the Storm Hardening Plan for the 2010 thru 2012 time period. The plan was approved in Docket No. 100264 under Consummating Order PSC-10-0724-CO-EI.

This is the FPUC annual update. The update includes the Annual Distribution Service Reliability Report required by Rule 25-6.0455, the Annual Wood Pole Inspection Report required by Order No. PSC-06-0144, and updates of our Storm Hardening Plan and Ten Storm Preparedness Initiatives, as required by Order No. PSC-06-0781. The update is divided into four primary sections: I. Reliability Indices; II. Wood Pole Inspections; III. Storm Hardening; and, IV. Storm Preparedness Initiatives. FPUC report forms, research reports, contractor reports, and other available supplemental supporting documentation are incorporated into the appropriate sections of the update. FPSC reliability index report forms have been updated and are also included.

FPUC has two electric divisions, Northwest (NW) Division, also referred to as Marianna, and Northeast (NE) Division, also referred to as Fernandina Beach. In some cases, each division's results are reported separately. For example, NW has no transmission facilities. Therefore, only NE will be reporting on Storm Preparedness Initiatives #3 (Six Year Transmission Structure Inspections) and #4 (Storm Hardening of Existing Transmission Structures). Also, the two divisions are approximately 250 miles apart and, although they may supply resources to support one another during emergency situations, each division will prepare separate emergency response plans to address Initiative #10 (Natural Disaster Preparedness and Recovery Program). In other cases, consolidated reports or a combination of individual and consolidated reports provide a more complete overview and reports are prepared accordingly.

I. Reliability Indices

This section contains the FPUC Annual Distribution Service Reliability Report required by Florida Public Service Commission (FPSC) Rule 25-6.0455.

In addition to the supporting data provided by FPUC for clarification, the report was prepared using the forms developed by FPSC. Indices are reported on an ***actual*** and ***adjusted*** basis, as follows:

a. Total number of Outage Events (N), categorized by cause for the highest ten causes.

b. Identification of three percent (3%) of Primary Circuits (feeders) with the highest number of feeder breaker interruptions.

c. SAIDI, CAIDI, SAIFI, and L-Bar reliability indices for each division and by company total*.

Indices are calculated as follows:

SAIDI = System Average Interruption Duration Index $= \frac{\text{Total Customer Minutes of Interruption (CMI)}}{\text{Total Number of Customers Served (C)}}$

CAIDI = Customer Average Interruption Duration Index $= \frac{\text{Total Customer Minutes of Interruption (CMI)}}{\text{Total Number of Customer Interruptions (CI)}}$

SAIFI = System Average Interruption Frequency Index $= \frac{\text{Total Number of Customer Interruptions (CI)}}{\text{Total Number of Customers Served (C)}}$

L-Bar = Average Duration of Outage Events $= \frac{\text{Sum of All Outage Event Durations (L)}}{\text{Total Number of Outage Events (N)}}$

* The FPUC total electric retail customer count is well below 50,000. Per Rule 25-6.0455, (3) (c), MAIFIe and CEMI5 indices are not applicable (N/A) and not reported at this time.

Forms reporting ***actual*** data include <u>all</u> outage events. Forms reporting ***adjusted*** data exclude outage events directly caused by one or more of the following, if applicable:

a. Planned Service Interruptions;
b. A storm named by the National Hurricane Center;
c. A tornado recorded by the National Weather Service;
d. Ice on lines;
e. A planned load management event;
f. Electric generation or transmission events not governed by subsections 25-6.018 (2) and (3);
g. Extreme weather or fire events causing activation of the county emergency operation center.

Definitions from Rule 25-6.044 'Continuity of Service' are provided below for clarification:

a. **"Area of Service."** A geographic area where a utility provides retail electric service. An Area of Service can be the entire system, a district, or a sub-region of the utility's system in which centralized distribution service functions are carried out.

b. **"Average Duration of Outage Events (L-Bar)."** The sum of each Outage Event Duration (L) for all Outage Events occurring during a given time period, divided by the Number of Outage Events (N) over the same time period within a specific Area of Service.

c. **"Customer Average Interruption Duration Index (CAIDI)."** The average time to restore service to interrupted retail customers within a specified Area of Service over a given period of time. It is determined by dividing the sum of Customer Minutes of Interruption (CMI) by the total number of Service (aka Customer) Interruptions (CI) for the respective Area of Service.

d. **N/A** (CEMI5).

e. **"Customer Minutes of Interruption (CMI)".** For a given Outage Event, CMI is the sum of each affected retail customer's Service Interruption Duration.

f. thru h. **N/A** (MAIFIe)

i. **"Number of Customers Served (C)."** The sum of all retail customers on the last day of a given time period within a specific Area of Service.

j. **"Number of Outage Events (N)."** The sum of Outage Events for an Area of Service over a specified period of time.

k. **"Outage Event."** An occurrence that results in one or more individual retail customer Service Interruptions.

l. **"Outage Event Duration (L)."** The time interval, in minutes, between the time a utility first becomes aware of an Outage Event and the time of restoration of service to the last retail customer affected by that Outage Event.

m. **"Service Interruption."** The complete loss of voltage of at least one minute to a retail customer. (CI for one customer).

n. **"Service Interruption Duration."** The time interval, in minutes, between the time a utility first becomes aware of a Service Interruption and the time of restoration of service to that retail customer. (CMI for one customer).

o. **"System Average Interruption Duration Index (SAIDI)."** The average minutes of Service Interruption Duration per retail customer served within a specified Area of Service over a given period of time. It is determined by dividing the total Customer Minutes of Interruption (CMI) by the total Number of Customers Served (C) for the respective Area of Service.

p. **"System Average Interruption Frequency Index (SAIFI)."** The average number of Service Interruptions per retail customer within a specified Area of Service over a given period of time. It is determined by dividing the sum of Service (aka Customer) Interruptions (CI) by the total Number of Customers Served (C) for the respective Area of Service.

q. **"Planned Service Interruption."** A Service Interruption initiated by the utility to perform necessary scheduled activities, such as maintenance, infrastructure improvements, and new construction due to customer growth.

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ACTUAL

PART I

CAUSES OF OUTAGE EVENTS – ACTUAL

Utility Name: **Florida Public Utilities Company- NE Division** Year: **2013**

Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Vegetation	38	113.23	66.16
2. Corrosion	29	88.16	102.76
3. Other Weather	23	87.62	83.03
4. Planned Outage	23	652.63	81.44
5. Other	17	129.59	52.67
6. Animal	16	60.86	41.16
7. Unknown	14	72.95	82.97
8. Lightning	13	110.28	100.27
9. Xfmr Failure	10	170.59	137.23
10. Transmission	9	109.93	91.38
11. Named Storm - Andrea	7	74.69	67.51
12. Vehicle	6	154.66	121.88
13. Transmission/JEA	3	62.44	40.82
System Totals NE	208	162.74	76.41

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ADJUSTED

PART I

CAUSES OF OUTAGE EVENTS – ADJUSTED

Utility Name: **Florida Public Utilities Company- NE Division** Year: **2013**

Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Vegetation	38	113.23	66.16
2. Corrosion	29	88.16	102.76
3. Other Weather	23	87.62	83.03
4. Other	17	129.59	52.67
5. Animal	16	60.86	41.16
6. Unknown	14	72.95	82.97
7. Lightning	13	110.28	100.27
8. Xfmr Failure	10	170.59	137.23
9. Vehicle	6	154.66	121.88
System Totals NE	166	103.26	80.54

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ACTUAL

PART I

CAUSES OF OUTAGE EVENTS – ACTUAL			
Utility Name: **Florida Public Utilities Company- NW Division**		Year: **2013**	
Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Other Weather	276	140.44	133.65
2. Animal	259	55.67	45.59
3. Vegetation	227	77.52	88.65
4. Unknown	81	62.18	67.68
5. Corrosion	36	94.48	53.19
6. Lightning	35	75.58	96.37
7. Xfmr Failure	19	135.44	108.02
8. Planned Outage	16	69.11	60.17
9. Other	15	57.75	55.96
10. Vehicle	10	93.60	65.69
11.			
12.			
System Totals NW	974	89.67	97.21

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ADJUSTED

PART I

CAUSES OF OUTAGE EVENTS – ADJUSTED

Utility Name: **Florida Public Utilities Company – NW Division** Year: **2013**

Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Other Weather	276	140.44	133.65
2. Animal	259	55.67	45.59
3. Vegetation	227	77.52	88.65
4. Unknown	81	62.18	67.68
5. Corrosion	36	94.48	53.19
6. Lightning	35	75.58	96.37
7. Xfmr Failure	19	135.44	108.02
8. Other	15	57.75	55.96
9. Vehicle	10	93.60	65.69
System Totals: NW	958	90.02	98.49

PSC/ECR 102-1(b) (8/06)
Incorporated by reference in Rule 25-6.0455,
Florida Administrative Code

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ACTUAL

CAUSES OF OUTAGE EVENTS – ACTUAL

Utility Name: **Florida Public Utilities Company- FPUC Total** Year: **2013**

Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Other Weather	299	136.37	118.38
2. Animal	275	55.98	44.91
3. Vegetation	265	82.64	81.51
4. Unknown	95	63.77	70.47
5. Corrosion	65	91.66	71.88
6. Lightning	48	84.98	97.67
7. Planned Outage	39	413.24	74.09
8. Other	32	95.92	54.73
9. Xfmr Failure	29	147.56	125.16
10. Vehicle	16	116.50	69.92
11. Transmission	9	109.93	91.38
12. Named Storm - Andrea	7	74.69	67.51
13. Transmission/JEA	3	62.44	40.82
System Totals FPUC	1182	102.53	84.13

PSC/ECR 102-1(a) (8/06)
Incorporated by reference in Rule 25-6.0455,
Florida Administrative Code

FLORIDA PUBLIC SERVICE COMMISSION
ANNUAL DISTRIBUTION SERVICE RELIABILITY REPORT – ADJUSTED

PART I

CAUSES OF OUTAGE EVENTS – ADJUSTED

Utility Name: **Florida Public Utilities Company- FPUC Total** Year: **2013**

Cause (a)	Number of Outage Events(N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Other Weather	299	136.37	118.38
2. Animal	275	55.98	44.91
3. Vegetation	265	82.64	81.51
4. Unknown	95	63.77	70.47
5. Corrosion	65	91.66	71.88
6. Lightning	48	84.98	97.67
7. Other	32	95.92	54.73
8. Xfmr Failure	29	147.56	125.16
9. Vehicle	16	116.50	69.92
System Totals FPUC	1,124	91.97	93.31

PART II

THREE PERCENT FEEDER LIST – ACTUAL

Utility Name: Florida Public Utilities Company — Year: 2013

Primary Circuit Id. No. or Name (a)	Sub-station Origin (b)	Location (c)	Number of Customers: Residential (d)	Commercial (e)	Industrial (f)	Other (g)	Total (h)	Outage Events "N" (i)	Avg Duration "L-Bar" (j)	CAIDI (k)	Listed Last Year? (l)	No. of Years in the Last 5 (m)	Corrective Action Completion Date (n)
102	AIP	Northeast	1700	31	0	0	1731	3	189.17	189.17	NO	NO	N/A
9512	Marianna	Northwest	705	290	0	0	995	3	149	149	NO	NO	N/A

PART II

THREE PERCENT FEEDER LIST – ADJUSTED

Utility Name: Florida Public Utilities Company Year: 2013

Primary Circuit Id. No. or Name (a)	Sub-station Origin (b)	Location (c)	Number of Customers: Residential (d)	Commercial (e)	Industrial (f)	Other (g)	Total (h)	Outage Events "N" (i)	Avg Duration "L-Bar" (j)	CAIDI (k)	Listed Last Year? (l)	No. of Years in the Last 5 (m)	Corrective Action Completion Date (n)
211	JLT	Northeast	1600	82	0	0	1682	3	52.51	52.56	No	2	N/A
9512	Marianna	Northwest	705	290	0	0	995	3	149	149	NO	NO	N/A

PART III

SYSTEM RELIABILITY INDICES – ACTUAL

Utility Name: **Florida Public Utilities Company** Year: 2013

District or Service Area (a)	SAIDI (b)	CAIDI (c)	SAIFI (d)	MAIFIe (e)	CEMI5 (f)
NE Division	313.90	76.41	4.11	N/A*	N/A*
NW Division	290.29	97.21	2.99	N/A*	N/A*
System Averages	303.32	84.13	3.61	N/A*	N/A*

* Total # of Electric Retail Customers is well below 50,000. N/A by Rule 25-6.0455 (3)(c)

PSC/ECR 102-3(a) (8/06)
Incorporated by reference in Rule 25-6.0455,
Florida Administrative Code

PART III

SYSTEM RELIABILITY INDICES – ADJUSTED

Utility Name: **Florida Public Utilities Company** Year: 2013

District or Service Area (a)	SAIDI (b)	CAIDI (c)	SAIFI (d)	MAIFIe (e)	CEMI5 (f)
NE Division	76.50	80.54	0.95	N/A*	N/A*
NW Division	284.32	98.49	2.89	N/A*	N/A*
System Averages	169.66	93.31	1.82	N/A*	N/A*

* Total # of Electric Retail Customers is well below 50,000. N/A by Rule 25-6.0455 (3)(c)

2013 - Reliability Indicators By Feeder FPUC – NE (Actual)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
102 South Fletcher	22	118.74	99.15	78,134	788	2,612		
104 Parkway South\	2	227.05	227.05	454	2	454		
110 Plantation Roadside	3	64.29	55.89	838	15	193		
111 Plantation Fieldside	8	118.42	104.33	8,034	77	947		
209 Fifteenth Street	12	128.96	139.21	433,911	3,117	1,548		
210 Buss Tie	12	102.11	93.28	131,248	1,407	1,225		
211 Jasmine Street	26	156.38	54.21	281,964	5,201	4,066		
212 Eleventh Street	26	96.60	34.94	40,631	1,163	2,512		
214 Clinch Drive	13	88.48	66.28	7,291	110	1,150		
215 Sadler, Nectarine, So.14th	9	148.48	46.02	46,162	1,003	1,336		
310 Bonnieview	11	74.39	69.69	21,115	303	818		
311 Bailey	54	294.81	74.59	417,260	5,594	15,920		
Gcb 201 - 69kv	3	51.92	51.92	311	6	156		
All FEEDERS	2	20.91	20.91	633,564	30,302	42		
Aip Substation - All Fdrs	3	189.17	189.20	2,767,122	14,625	568		
Gcb 202 - 69kv	2	151.89	151.89	304	2	304		
	208	162.74	76.41	4,868,343	63,715	33,850	313.90	4.11

Total No. of Customers at end of 2013 ==> **15,509**

2013 - Reliability Indicators By Feeder FPUC - NE (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
102 South Fletcher	20	109.86	98.99	77,610	784	2,197		
104 Parkway South\	1	138.25	138.25	138	1	138		
110 Plantation Roadside	3	64.29	55.89	838	15	193		
111 Plantation Fieldside	8	118.42	104.33	8,034	77	947		
209 Fifteenth Street	9	97.88	139.23	432,881	3,109	881		
210 Buss Tie	10	100.15	97.21	72,228	743	1,001		
211 Jasmine Street	22	127.16	54.00	278,684	5,161	2,798		
212 Eleventh Street	24	97.16	72.19	24,473	339	2,332		
214 Clinch Drive	13	88.48	66.28	7,291	110	1,150		
215 Sadler, Nectarine, So.14th	8	87.76	45.44	45,528	1,002	702		
310 Bonnieview	10	73.29	69.26	20,432	295	733		
311 Bailey	38	107.04	70.53	218,231	3,094	4,068		
	166	103.26	80.54	1,186,367	14,730	17,140	76.50	0.95

Total No. of Customers at end of 2013 ==> **15,509**

2013 - Reliability Indicators By Feeder FPUC - NW (Actual)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
Altha	71	104.76	86.37	157,271	1,821	7,438		
Blountstwn	12	99.06	104.83	20,127	192	1,189		
Bristol	67	60.17	50.11	108,795	2,171	4,032		
College	120	90.16	68.40	300,203	4,389	10,819		
Cottondale	122	85.12	94.03	618,706	6,580	10,385		
Dogwood Ht	26	66.31	69.74	18,552	266	1,724		
Family Dol	1	69.30	69.30	69	1	69		
Greenwood	131	95.36	137.75	880,489	6,392	12,493		
Hospital	42	109.17	127.30	194,003	1,524	4,585		
Hwy 90e	83	82.77	121.48	165,212	1,360	6,870		
Hwy 90w	25	106.82	87.73	33,512	382	2,671		
Ind Park	2	159.46	227.38	10,459	46	319		
Indian Spr	82	93.76	89.54	152,846	1,707	7,688		
Prison	8	94.66	104.99	1,470	14	757		
Railroad	36	94.66	132.13	512,388	3,878	3,408		
South St	146	88.34	70.08	484,174	6,909	12,897		
	974	89.67	97.21	3,658,278	37,632	87,343	290.29	2.99

Total No. of Customers at end of 2013 ==> **12,602**

2013 - Reliability Indicators By Feeder FPUC - NW (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
Altha	71	104.76	86.37	157,271	1,821	7,438		
Blountstwn	12	99.06	104.83	20,127	192	1,189		
Bristol	63	60.81	49.44	94,029	1,902	3,831		
College	120	90.16	68.40	300,203	4,389	10,819		
Cottondale	121	85.50	96.88	605,623	6,251	10,345		
Dogwood Ht	23	66.21	69.14	14,934	216	1,523		
Family Dol	1	69.30	69.30	69	1	69		
Greenwood	128	96.55	141.17	877,683	6,217	12,358		
Hospital	41	108.91	127.31	193,643	1,521	4,465		
Hwy 90e	83	82.77	121.48	165,212	1,360	6,870		
Hwy 90w	25	106.82	87.73	33,512	382	2,671		
Ind Park	2	159.46	227.38	10,459	46	319		
Indian Spr	81	93.55	84.21	114,352	1,358	7,578		
Prison	6	80.22	96.65	1,063	11	481		
Railroad	36	94.66	132.13	512,388	3,878	3,408		
South St	145	88.78	70.58	482,381	6,835	12,873		
	958	90.02	98.49	3,582,951	36,380	86,237	284.32	2.89

Total No. of Customers at end of 2013==> **12,602**

FPUC 2013 – Reliability Indicators and Analysis

FPUC's reliability indicators continue to be heavily influenced by the weather as well as the relatively small size of our territories when compared to other larger investor owned utilities. This situation generates a greater level of volatility in our reliability indices. However, both NE and NW Divisions continue to invest in infrastructure upgrades and renovations which continue to generate improvements in all our reliability indicators from the 5 year high values in 2009. Clear examples of this are the 2013 decreases in all FPU's combined indicators which show reductions ranging from 28.73% to 10.44% from the values in 2009. These improvements are direct results of closely implementing the initiatives described in this report.

The NE Division has continued substantial reductions in SAIDI with a 45.78% decrease from 141, 08 in 2012 to 76.50 in 2013. Likewise, they obtained a 24.63% reduction in CAIDI from 106.86 in 2012 to 80.54 in 2013, a 28.03% reduction in SAIFI from 1.32 in 2012 to 0.95 in 2013, and a 9.34% reduction in L-BAR from 113.9 in 2012 to 103.36 in 2013.

While the NW division saw substantial increases in SAIDI and SAFI, it was mainly due to the severe weather that affected their territory. This can be seen on page 9 above on the table labeled "Causes of Outage Events – Adjusted". This table outlines that the highest number of events are due to "Other Weather", which are none excludable severe storms. FPUC will continue to monitor all the reliability indices and outage causes to adjust and improve our current reliability programs.

FPUC 2013 – Description of Excluded Events for Named Storms, Transmission, Distribution, and Substations

Named Storms

The NW was not impacted by any named storms in 2013. However, the NE Division experienced several outages, as a result of named storm Andrea, at the beginning of the hurricane season on June 6, 2013

Transmission, Distribution and Substation

The NE Division was affected by several 69KV transmission outages during 2013 that were mainly related to lightning. As a result, FPUC performed a study which identified lightning arrestors and grounding as the root cause of the failures. The NE division, in the upcoming years, will begin implementing a new lightning arrestor and grounding standard along the areas that have been most affected by these events. The other major outage was due to a temporary loss of FPU's power supplier, Jacksonville Electric Authority (JEA), which was performing maintenance at one of their 138KV substations. This event affected the whole NE division on

December 27, 2013. In all cases crews were immediately dispatched and power was restored to all customers as soon as possible.

The NE and NW Divisions, as noted below in the Excluded Events Tables, had several planned outages to perform maintenance to different sections of the distribution system.

The NW did not experience any substation and transmission related events in 2013.

2013 NE Division Excluded Events					
Date	Feeder	Exclusion	Aff Cust	L	CMI
3/23/13	AIP SUBSTATION - ALL FDRS	Transmission	4,879	294	1,432,068
4/11/13	210 BUSS TIE	Transmission	659	89	58,343
4/11/13	212 ELEVENTH STREET	Transmission	822	19	15,837
4/17/13	311 BAILEY	Planned Outage	6	120	722
4/17/13	210 BUSS TIE	Planned Outage	5	135	676
4/18/13	311 BAILEY	Planned Outage	2	89	178
4/23/13	311 BAILEY	Planned Outage	7	200	1,403
4/23/13	311 BAILEY	Planned Outage	4	119	477
4/24/13	311 BAILEY	Planned Outage	22	109	2,404
4/25/13	310 BONNIEVIEW	Planned Outage	8	85	683
5/1/13	311 BAILEY	Planned Outage	13	2	23
5/6/13	311 BAILEY	Planned Outage	2	209	419
5/7/13	311 BAILEY	Planned Outage	2	59	118
5/14/13	311 BAILEY	Planned Outage	7	170	1,192
5/14/13	311 BAILEY	Planned Outage	1	89	89
5/21/13	311 BAILEY	Planned Outage	3	10,224	30,671
5/21/13	311 BAILEY	Planned Outage	2	120	240
5/22/13	311 BAILEY	Planned Outage	4	135	541
6/1/13	215 SADLER, NECTARINE, SO.14TH	Planned Outage	1	634	634
6/6/13	211 JASMINE STREET	Named Storm - Andrea	30	61	1,822
6/6/13	212 ELEVENTH STREET	Named Storm - Andrea	2	160	321
6/6/13	209 FIFTEENTH STREET	Named Storm - Andrea	6	73	436
6/6/13	211 JASMINE STREET	Named Storm - Andrea	8	36	287
6/6/13	102 SOUTH FLETCHER	Named Storm - Andrea	3	54	163
6/6/13	311 BAILEY	Named Storm - Andrea	65	69	4,517
6/6/13	311 BAILEY	Named Storm - Andrea	82	69	5,687
6/24/13	211 JASMINE STREET	Planned Outage	1	710	710
6/24/13	211 JASMINE STREET	Planned Outage	1	461	461
7/13/13	209 FIFTEENTH STREET	Planned Outage	1	70	70
8/1/13	AIP SUBSTATION - ALL FDRS	Transmission	4,874	63	307,062
8/5/13	102 SOUTH FLETCHER	Planned Outage	1	361	361
8/22/13	AIP SUBSTATION - ALL FDRS	Transmission	4,872	211	1,027,992
8/22/13	311 BAILEY	Planned Outage	2,278	66	150,348

9/17/13	GCB 202 - 69KV	Transmission	1	233	233
10/28/13	GCB 201 - 69KV	Transmission	2	64	128
10/28/13	GCB 201 - 69KV	Transmission	2	16	32
10/28/13	All FEEDERS	Transmission	15,151	1	15,151
11/2/13	209 FIFTEENTH STREET	Planned Outage	1	524	524
12/16/13	104 PARKWAY SOUTH\	Planned Outage	1	316	316
12/27/13	All FEEDERS	Transmission/JEA	15,151	41	618,413
12/27/13	GCB 202 - 69KV	Transmission/JEA	1	71	71
12/27/13	GCB 201 - 69KV	Transmission/JEA	2	76	152

2013 NW Division Excluded Events

Date	Feeder	Cause	Aff Cust	L	CMI
3/14/13	SOUTH ST	Planned Outage	74	24	1,793
6/7/13	PRISON	Planned Outage	1	145	145
6/7/13	PRISON	Planned Outage	2	131	262
6/14/13	BRISTOL	Planned Outage	92	58	5,338
6/18/13	DOGWOOD HT	Planned Outage	4	53	212
7/8/13	GREENWOOD	Planned Outage	1	108	108
7/15/13	BRISTOL	Planned Outage	104	62	6,415
8/17/13	HOSPITAL	Planned Outage	3	120	360
8/21/13	BRISTOL	Planned Outage	50	43	2,150
9/18/13	DOGWOOD HT	Planned Outage	23	23	539
9/23/13	BRISTOL	Planned Outage	23	38	863
9/26/13	DOGWOOD HT	Planned Outage	23	125	2,867
11/11/13	GREENWOOD	Planned Outage	4	11	43
11/12/13	GREENWOOD	Planned Outage	170	16	2,655
11/25/13	COTTONDALE	Planned Outage	329	40	13,083
12/16/13	INDIAN SPR	Planned Outage	349	110	38,495

II. Wood Pole Inspections

Introduction

To comply with FPSC Order No. PSC-06-0144, in 2008 Florida Public Utilities Co. (FPUC) implemented an 8-year cycle wood pole inspection program. The most current edition of the National Electric Safety Code (NESC) serves as a basis for the design of replacement poles for wood poles that fail inspection. Grade 'B' construction, as described in Section 24 of the NESC, has been adopted as the standard of construction for designing new pole installations and the replacement of reject poles in each FPUC Electric Division (NE & NW). Extreme wind loading, as specified in figure 250-2(d) of the NESC, has been adopted, as follows: 130 mph wind speed for wind loading in NE Division (Fernandina); 120 mph wind speed for wind loading in NW Division (Marianna).

Wood pole inspections are performed by a qualified wood pole inspection contractor. Inspection results are summarized for each division using the Wood Pole Inspection Reports included in this section. Also included are bar charts and tables that show inspection results summary, failure rates, and pole ages.

The number of inspections may vary from year-to-year based upon a variety of factors. FPUC will continue to work diligently to complete all required wood pole inspections during the eight year wood pole inspection cycle.

Inspection Process

The first inspection is a visual inspection to determine if there are any defects that require pole replacement. If the visual inspection indicates that the pole is not suited for continued use, it is rejected by the contractor and reported to FPUC for follow-up.

If the pole passes visual inspection, the pole is sound and bore tested to determine the internal condition of the pole. If the sound and bore inspection indicates that the pole is not suited for continued use, the pole is rejected by the contractor and reported to FPUC for follow-up.

If the pole passes the sound and bore test, the pole is excavated a minimum of 18 inches in depth and tested. If this test indicates the pole is suitable for continued service, the pole is treated and backfilled. If this test indicates the pole is not suited for continued use, it is rejected by the contractor and reported to FPUC for follow-up.

During 2013, FPUC submitted the 2013-2015 Storm Hardening Plan for PSC approval. The plan introduced modified criteria for CCA pole inspections. However, the plan was approved after 2013 pole inspections were begun. Therefore, the criteria used were those contained in the 2010-2012 Storm Hardening Plan. CCA poles less than 16 years of age were visually inspected, sounded, and selectively bored. Boring was performed only if internal decay was suspected. Unless a pole failed sound and bore, a full excavation was not performed on these poles. To ensure that more rigorous inspections were not warranted, FPUC required its contractor to perform full excavation sampling of at least 1.0% of CCA poles under 16 years of age and planned for current cycle inspection. The random sample inspections for 2013 produced no reject failures for 2013.

Strength and Loading Assessment

The contractor performs Strength Assessment tests on selected poles to compare the current measured circumference to the original circumference of the pole. The effective circumference of the pole is determined to ensure that the current condition of the pole meets the requirements of NESC Section 26 "Strength Requirements". Beginning in 2010, pole inspection criteria were enhanced to include LoadCalc analysis on poles with remaining strength at or below 67%. If the 'required' remaining strength resulting from the combined strength and load analysis indicates that the pole is not suited for continued use, the contractor rejects the pole and reports it to FPUC for follow-up.

Poles having 3rd party attachments of ½" or larger in diameter are assessed for loading by the contractor who uses a program called LoadCalc. When conducting the Loading Assessment, span lengths, attachment heights, wire sizes, and 3rd party attachments are analyzed to estimate pole loading. Poles identified by the contractor as being loaded at or above 100% are re-evaluated by FPUC engineers using a program called PoleForeman. NESC Grade B construction & 60 mph winds provide the basis for calculations. Poles loaded at or above 100% following re-evaluation are replaced. Additional discussion about 3rd party attachments is provided in Storm Preparedness Initiatives section under Initiative #2, "Joint Use Pole Attachment Audit".

Post Inspection Follow-Up

The contractor provides FPUC with follow up reports.

Poles Needing Maintenance Report: Maintenance items are provided to FPUC construction employees. The poles are re-inspected and assigned a priority based upon potential hazard to public and employee safety. Repairs are then made in order of priority.

Reject Poles Report: FPUC policy is to replace all reject poles in lieu of bracing "restorable" reject poles. Poles are prioritized for replacement using the reject severity level awarded by the inspector as the basis. Each pole is analyzed by FPUC engineers. A computer program called PoleForeman is used to make sure the new poles meet the storm hardening criteria discussed in the first paragraph of this section.

The list of reject poles is provided to 3rd party attachers so they may give feedback concerning planned attachments that require increased pole size for added loading.

Summary

FPUC collects and stores pole inspection data upon completion of annual wood pole inspections. The contractor provides FPUC with wood pole inspection data that includes pole location, size, class, test results, and general comments. The contractor provides inspection summary data via an On-line Data Center that allows FPUC to create specific reports and view detailed or summary information. The On-line Data Center is essential for post inspection follow up.

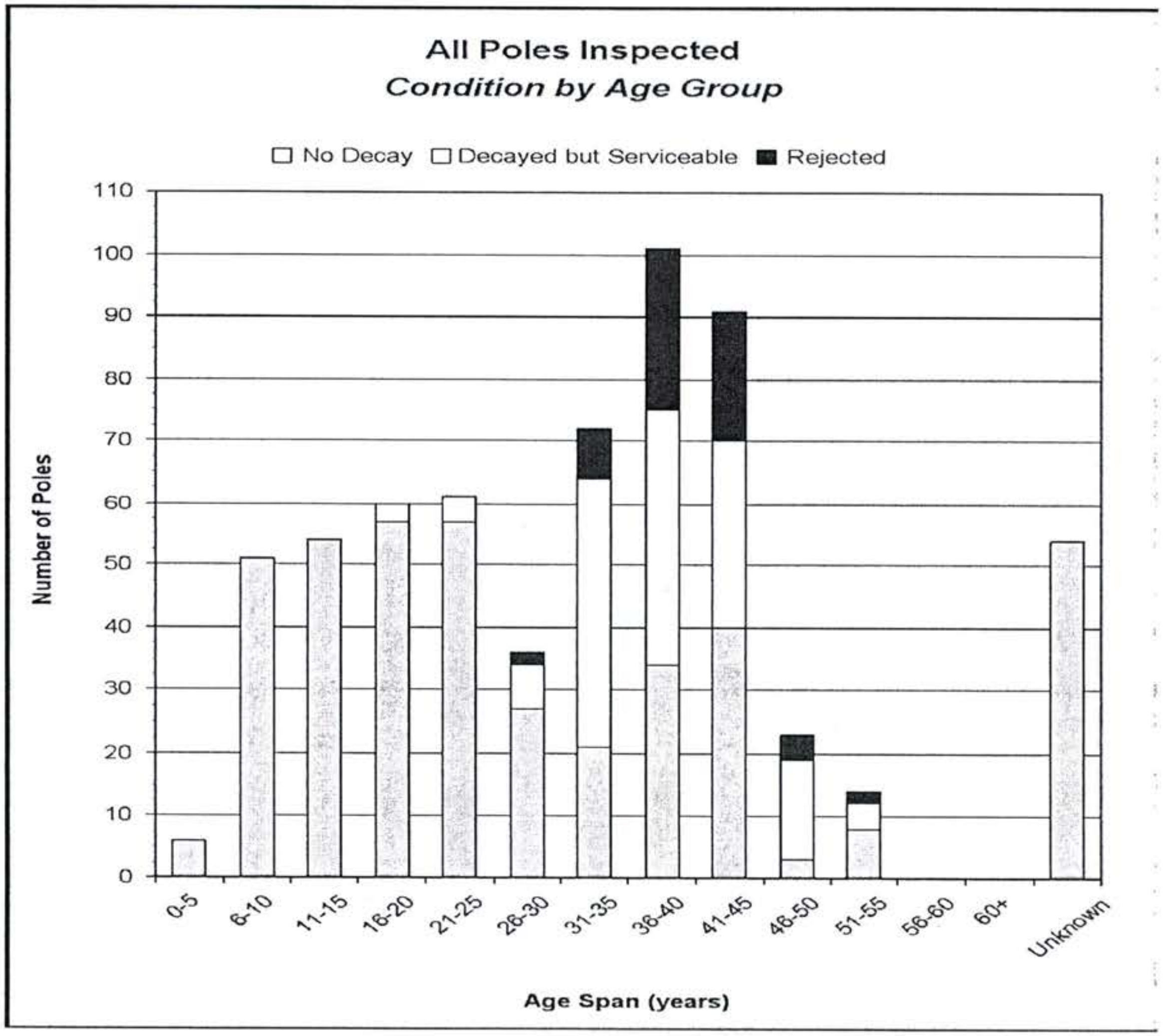
The inspection contractor is required to perform quality control assessments of their work to ensure FPUC pole inspection requirements are being met. The contractor provides documentation that these assessments have taken place.

Florida Public Utilities Company - NE Division
Annual Wood Pole Inspection Report
Cycle Year #6 of 8 Year Cycle
(Inspection Year 2013)

a	b	c	d	e	f	g	h	i	j	k	l	m	n	o
Total # of wood poles in NE Division	# of pole inspections planned for this year	Backlog included in plans for this year	# of pole inspections completed this year	# of poles failing inspection this year	% failure rate this year	# failures replaced this year	# failures repaired this year	Total # of failures remaining to be replaced	Total # of failures remaining to be repaired	# of poles requiring maint. follow-up this year	# of poles overloaded this year	Total # of poles inspected in 8 yr cycle to date	Total % of poles inspected in 8 yr cycle to date	# of pole inspections planned next year
4872	**595**	**0**	**623**	**63**	**10.1%**	**52**	**N/A***	**13**	**N/A***	**83**	**1**	**3873**	**79.5%**	**587**

If d < b, provide explanation	Include reason for variance, resulting backlog, and plans to address backlog: N/A.
If g + h < e, provide explanation	Include reason for variance, resulting backlog, and plans to address backlog: N/A * Present FPUC policy is to replace all failure poles in lieu of bracing "restorable" failure poles. Therefore, columns (h) and (j) are not applicable (N/A) to FPUC at this time.
Additional Information	Random sample full excavation inspections were completed on at least one percent of CCA poles planned for current cycle inspections. Random sample inspections produced no results to indicate more rigorous inspections of CCA poles are necessary at this time.

NE Division


All Poles Inspected
Condition by Age Group
No Decay
Decayed but Serviceable
Rejected
Number of Poles
0
10
20
30
40
50
60
70
80
90
100
110
0-5
6-10
11-15
16-20
21-25
26-30
31-35
36-40
41-45
46-50
51-55
56-60
60+
Unknown
Age Span (years)

NE Division ed

Condition by Age Group

Age Span (years)	No Decay		Decayed but Serviceable					Rejected					Total Poles Inspected	
	Number	%	Internal Decay	External Decay	Other Decay	Number	%	Internal Decay	External Decay	Other Decay	Number	%	Number	%
0-5	6	100%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6	1%
6-10	51	100%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	51	8%
11-15	54	100%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	54	9%
16-20	57	95%	0	3	0	3	5%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60	10%
21-25	57	93%	0	3	1	4	7%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61	10%
26-30	27	75%	0	6	1	7	19%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	36	6%
31-35	21	29%	0	38	5	43	60%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72	12%
36-40	34	34%	0	38	3	41	41%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101	16%
41-45	40	44%	0	27	3	30	33%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91	15%
46-50	3	13%	0	14	2	16	70%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	23	4%
51-55	8	57%	0	4	0	4	29%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	14	2%
56-60	0	0%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0%
60+	0	0%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0%
Unknown	54	100%	0	0	0	0	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	54	9%
Total	**412**	**66%**	**0**	**133**	**15**	**148**	**24%**	**0**	**63**	**0**	**63**	**10%**	**623***	

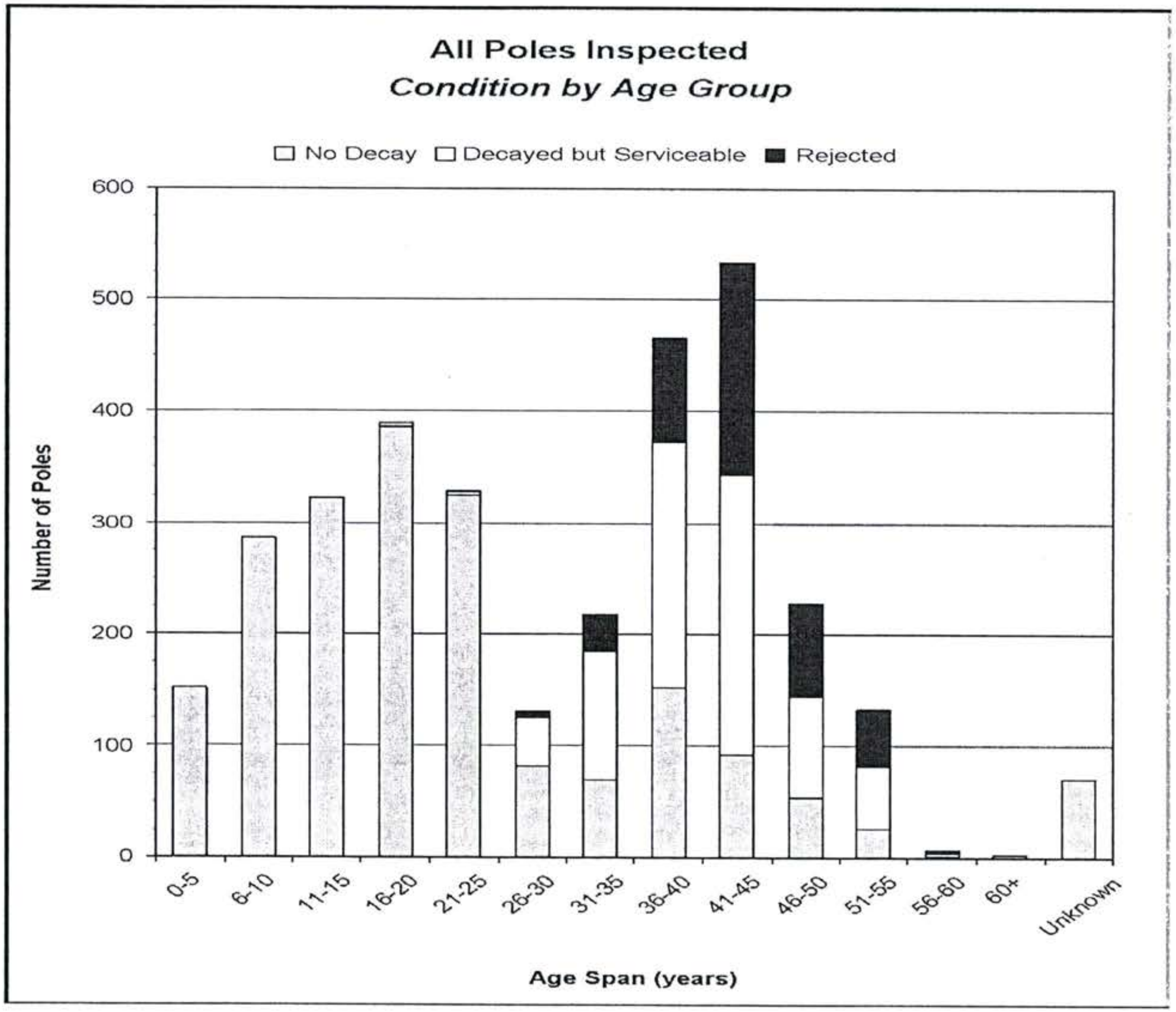
* Average Age: 29.5 years

Florida Public Utilities Company - NW Division
Annual Wood Pole Inspection Report
Cycle Year #6 of 8 year Cycle
(Inspection Year 2013)

a	b	c	d	e	f	g	h	i	j	k	l	m	n	o
Total # of wood poles in NW Division	# of pole inspections planned for this year	Backlog included in plans for this year	# of pole inspections completed this year	# of poles failing inspection this year	% failure rate this year	# failures replaced this year	# failures repaired this year	Total # of failures remaining to be replaced	Total # of failures remaining to be repaired	# of poles requiring maint. follow-up this year	# of poles overloaded this year	Total # of poles inspected in 8 yr cycle to date	Total % of poles inspected in 8 yr cycle to date	# of pole inspections planned next year
21279	**2394**	**0**	**3264**	**460**	**14.1%**	**83**	**N/A***	**844**	**N/A***	**973**	**34**	**17362**	**81.6%**	**1959**

If d < b, provide explanation	Include reason for variance, resulting backlog, and plans to address backlog: N/A. .
If g + h < e, provide explanation	Include reason for variance, resulting backlog, and plans to address backlog: N/A * Present FPUC policy is to replace all failure poles in lieu of bracing "restorable" failure poles. Therefore, columns (h) and (j) are not applicable (N/A) to FPUC at this time.
Additional Information	Random sample full excavation inspections were completed on at least one percent of CCA poles planned for current cycle inspections. Random sample inspections produced no results to indicate more rigorous inspections of CCA poles are necessary at this time.

NW Division


All Poles Inspected
Condition by Age Group
No Decay
Decayed but Serviceable
Rejected
Number of Poles
600
500
400
300
200
100
0
0-5
6-10
11-15
16-20
21-25
26-30
31-35
36-40
41-45
46-50
51-55
56-60
60+
Unknown
Age Span (years)

NW Division

All Poles Inspected
Condition by Age Group

Age Span (years)	No Decay		Decayed but Serviceable		Rejected		Total Poles Inspected	
	Number	Percentage	Number	Percentage	Number	Percentage	Number	Percentage
0-5	152	100%	0	0%	0	0%	152	5%
6-10	286	100%	0	0%	0	0%	286	9%
11-15	322	100%	0	0%	0	0%	322	10%
16-20	386	99%	3	1%	0	0%	389	12%
21-25	324	99%	4	1%	0	0%	328	10%
26-30	82	63%	42	32%	6	5%	130	4%
31-35	69	32%	116	53%	33	15%	218	7%
36-40	152	33%	220	47%	94	20%	466	14%
41-45	92	17%	251	47%	190	36%	533	16%
46-50	54	24%	90	40%	83	37%	227	7%
51-55	26	20%	56	42%	51	38%	133	4%
56-60	1	14%	3	43%	3	43%	7	0%
60+	2	100%	0	0%	0	0%	2	0%
Unknown	71	100%	0	0%	0	0%	71	2%
Total	**2019**	**62%**	**785**	**24%**	**460**	**14%**	**3264***	

* Average Age: 28.7 years

III. Storm Hardening Update

Introduction

This is the required annual update of the FPUC Storm Hardening Plan. Wood pole inspection is addressed in more detail in Section II of this update. More extensive updates for the ten storm preparedness initiatives can be found in Section IV.

Compliance with NESC Requirements:

The National Electric Safety Code (NESC) serves as a basis for the design and construction of new and replacement FPUC facilities. Pursuant to subsection 25-6.0345 (2), F.A.C., all FPUC facilities were installed in accordance with NESC requirements in effect at the time of their installation. To enhance FPUC storm hardening efforts, more stringent Grade 'B' construction, as described in Section 24 of the 2007 edition of the NESC, has been adopted as the standard for the design and installation of all future new and replacement poles in each FPUC Electric Division (NE & NW).

Extreme Wind Loading:

Extreme wind loading, as specified in figure 250-2(d) of the 2007 edition of the NESC, has been adopted, as follows: 130 mph wind speed for wind loading in NE Division (Fernandina); and, 120 mph wind speed for wind loading in NW Division (Marianna).

Mitigation of Damage Due to Storm Surge and Flooding:

FPUC continues to develop specifications for mitigating damage to underground and overhead distribution and transmission facilities caused by flooding and storm surges. Additionally, FPUC is participating along with other investor owned, cooperative, and municipal electric utilities in the Public Utility Research Center (PURC) research regarding hurricane winds and storm surge within the state.

FPUC transmission facilities are located in the Northeast (Florida) Division only. Transmission lines constructed near and across coastal waterways were originally designed to meet, at a minimum, NESC requirements for those applications. Where necessary, foundations and casings were used to stabilize the structures due to the soil conditions.

Some overhead distribution lines in both divisions are subject to storm surges and flooding. Lines located near the coast or inland waterways that are subject to storm surges or flooding are continually evaluated. Additional supporting mechanisms are installed when practicable. This includes storm guys or pole bracing, as needed. Storm guys or bracing are being placed so that additional support is achieved perpendicular to the distribution line. Potentially affected lines that have reclosers, capacitors, or regulators that require electronic controls have associated controls mounted above maximum anticipated surge or flood levels.

Underground distribution lines subject to potential storm surges and flooding are mainly located in Northeast Florida Division. Storm hardening specifications include the use of reinforced concrete pads with legs on each corner that are poured approximately two feet into the ground to provide additional stability. Equipment is securely attached to the pad. Underground distribution lines are placed in conduit but are not typically encased in concrete. Future installations of underground distribution feeders will be evaluated based upon potential exposure to storm surges and flooding. Additional information and conclusions from research performed by the PURC will be included in the evaluation. If it is determined that storm surges could cause excessive damage, the installation may be encased in concrete ducts if feasible and validated by research.

Placement of New and Replacement Facilities:

Accessible locations are necessary for the efficient and safe installation and maintenance of FPUC facilities. Therefore, facilities are placed along public rights of way or located on private easements that are readily accessible from public streets. Placement of facilities along rear lot lines will not occur except in certain commercial applications were easily accessible concrete or asphalt driveways are located at the rear of the development or in residential neighborhoods with alleyways designed specifically for the purpose of installing utility services behind the homes.

Deployment Strategy:

FPUC has a fully implemented storm hardening strategy. Significant areas of note for 2013 include:

1. During 2013, each division completed the sixth year of pole inspections for the 8 year cycle wood pole inspection program. Specific results are reported in Section II - Wood Pole Inspections.
2. FPUC continues its Vegetation Management Program that includes trimming main feeders every three years, laterals every six years, and addressing danger trees as soon as possible. Additional information about the FPUC Vegetation Management Program can be found in Section IV - Storm Preparedness Initiatives, Initiative #1 - Vegetation Management Program for Distribution Circuits.
3. Pole loading inspections and follow up are performed annually in both divisions as part of the Wood Pole Inspection Program. More information about pole loading inspections and follow up can be found in Section II - Wood Pole Inspections, and Section IV - Storm Preparedness Initiatives, Initiative #2 - Joint Use Pole Attachment Audit.
4. FPUC owned transmission poles are only located in NE Division. Details about climbing inspections of transmission poles can be found in Section IV - Storm Preparedness Initiatives, Initiative #3 - Six Year Transmission Structure Inspection Program.
5. Section IV - Storm Preparedness Initiatives, Initiative #4 - Storm Hardening of Existing Transmission Structures contains additional information about transmission structure storm hardening.
6. New underground facilities are designed to mitigate damage from storm surges and flooding.
7. FPUC will continue to place facilities on public rights of way and, if this is not possible, will secure private easements to make sure facilities are easily accessible.

Communities and Areas Affected by Electric Infrastructure Improvements:

The majority of the items listed in the deployment strategy affect all areas of the FPUC electric service territory. The intent is to make sure both divisions benefit from these strategies. Transmission inspection and transmission storm hardening programs only affect the Northeast Florida Division since there are no FPUC owned transmission facilities in the Northwest Florida

Division at this time. Constructing distribution lines to comply with the NESC extreme wind loading standards is beneficial to both divisions and the communities they serve.

Upgrading of Joint Use Facilities

In 2012 two storm hardening projects took place in the NW division. Distribution facilities along Hartsfield Rd were relocated along the county ROW and storm hardened in the process. The Malone feeder between Greenwood and Malone began at the end of 2013 and will be complete mid-2014.

NE Division storm hardening projects planned for 2012 were placed on hold because the local government wanted to discuss undergrounding some of the overhead facilities associated with the projects. FPUC agreed to take another look at the projects to include conversion from overhead facilities to underground as soon as the local government made a formal request for preparation of a preliminary cost estimate. As of the end of 2013, no formal request had been received by FPUC. The two NE Division storm hardening projects submitted in the FPUC 2010-2012 Storm Hardening Plan have been placed on hold pending input from local government. Two new storm hardening projects are under development for the NE Division and will be included in the FPUC 2013-2015 Storm Hardening Plan. NE Division has continued to replace reject poles. Many of these reject poles have joint use facilities. New replacement poles were designed to accommodate joint use facilities and were installed in accordance with criteria found in the current addition of NESC guidelines for extreme wind loading conditions. The new installations were coordinated with joint users. Fifty two reject poles were replaced during 2013 in NE Division. Only three wooden transmission poles remain on the NE Division backlog. Due to the extended lead order time for building concrete poles, the three transmission poles will be replaced with concrete poles in 2014, along with twenty nine additional wooden transmission poles with significant damage that were discovered during the 2012 transmission climbing inspection.

IV. Storm Preparedness Initiatives

This is the FPUC required annual update of the ten storm preparedness initiatives.

Initiative #1 - Vegetation Management Programs for Distribution Circuits

FPUC continues to work towards the accomplishment of a three year vegetation management cycle on main feeders and a six year vegetation management cycle on laterals on the system.

The program includes the following:

1. Three year vegetation management cycle on all main feeders.
2. Six year vegetation management cycle on all laterals.
3. Increased participation with local governments to address improved overall reliability due to tree related outages.
4. Information made available to customers regarding the maintenance and placement of trees.

Based upon current tree trimming crew levels, the Company will make reasonable efforts to address the following :

1. Annual inspection of main feeders to critical infrastructure prior to the storm season to identify and perform the necessary trimming.
2. Address danger trees located outside the normal trim zone and located near main feeders as reported.

Performance Metrics: Adjusted data includes only activities that are budgeted and included in the Company's filed vegetation management plan. Unadjusted (actual) data includes all performance data, such as, hurricane performance and all other vegetation caused outage events FPUC believes to be excludable pursuant to 25-6.0455,F.A.C. The difference between unadjusted data and adjusted data are the storm reliability performance metrics.

The FPUC vegetation management program was implemented in 2008. Because the Company Program for trimming main Feeders is a Three Year Program, a Comparison Table is not necessary for Feeders. The Company Program for trimming Laterals is six years. FPUC will begin preparing Comparison Tables for Laterals when Six Year Cycle trimming has been completed in 2013 (2014 Report).

FPUC Consolidated Vegetation Management Performance Metrics – 2013

	Feeders			Laterals		
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.
(A) Number of Outages	3	3	0	262	262	0
(B) Customer Interruptions	4,373	4,373	0	8,339	8,339	0
(C) Miles Cleared	66.77	66.77	0	129.46	129.36	0.1
(D) Remaining Miles (Note 2 & 3)	27.51	27.51	0	-181.64	-181.64	0
(E) Outages per Mile [A ÷ (C + D)]	0.03	0.03	0.00	-5.02	-5.01	-0.01
(F) Vegetation CI per Mile [B ÷ (C + D)]	46.38	46.38	0.00	-159.81	-159.51	-0.31
(G) Number of Hotspot trims	192	192	0	NA	NA	NA
(H) All Vegetation Management Costs	$858,222	$858,222	0	(Note 4)	(Note 4)	(Note 4)
(I) Customer Minutes of Interruption	445,055	445,055	0	591,113	591,113	0
(J) Outage restoration costs	(Note 5)	(Note 5)	0	NA	NA	NA
(K) Vegetation Budget (current year)	$ 869,000	$ 869,000	$ -	NA	NA	NA
(L) Vegetation Goal (current year)	$ 869,000	$ 869,000	$ -	NA	NA	NA
(M) Vegetation Budget (next year)	$ 725,000	$ 725,000	$ -	NA	NA	NA
(N) Vegetation Goal (next year)	$ 725,000	$ 725,000	$ -	NA	NA	NA
(O) Trim-Back Distance	(Note 6)	(Note 6)	0	(Note 6)	(Note 6)	NA

Danger Trees (FPUC Totals) – Additional Questions
a) Number of danger trees removed? 338 (est)
b) Expenditures on danger tree removal? $44,000 (est)
c) Number of request for removals that were denied? 0
d) Avoided CI with danger trees removed (estimate)? _________
e) Avoided CMI with danger trees removed (estimate)? _________

Note 2: NE and NW Division uses GIS system to obtain miles of feeders and laterals.
Note 3: Remaining miles negative numbers indicate additional trimming that the required 3 and 6 year cycles.
Note 4: Vegetation management costs have not been separated between main feeders and laterals.
Note 5: Outage restoration costs have not been historically documented.
Note 6: Distribution is 10 feet and transmission (138KV is 30 feet and 69KV is 15 feet)
Note 8: For 2013 and beyond vegetation management metrics will be recalculated using new project management procedure.

NE Division Vegetation Management Performance Metrics - 2013

	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.
(A) Number of Outages	2	2	0	36	36	0
(B) Customer Interruptions	3,370	3,370	0	665	665	0
(C) Miles Cleared (Notes 1 & 2)	36.09	36.09	0	26.98	26.98	0
(D) Remaining Miles (Note 2 & 3)	-7.49	-7.49	0	-24.83	-24.83	0
(E) Outages per Mile [A ÷ (C + D)]	0.07	0.07	0	16.74	16.74	0
(F) Vegetation CI per Mile [B ÷ (C + D)]	117.83	117.83	0	309.30	309.30	0
(G) Number of Hotspot trims	0	0	0	0	0	0
(H) All Vegetation Management Costs	$298,709	$298,709	0	(Note 4)	(Note 4)	(Note 4)
(I) Customer Minutes of Interruption	193,503	193,503	0	73,438	73,438	0
(J) Outage restoration costs	(Note 5)	(Note 5)	NA	NA	NA	NA
(K) Vegetation Budget (current year)	$290,000	$290,000	$ -	NA	NA	NA
(L) Vegetation Goal (current year)	$290,000	$290,000	$ -	NA	NA	NA
(M) Vegetation Budget (next year)	$275,000	$275,000	$ -	NA	NA	NA
(N) Vegetation Goal (next year)	$275,000	$275,000	$ -	NA	NA	NA
(O) Trim-Back Distance	(Note 6)	(Note 6)	0	(Note 6)	(Note 6)	NA

Danger Trees (NE Division) – Additional Questions
a) Number of danger trees removed? 16
b) Expenditures on danger tree removal? $4,000 (est)
c) Number of request for removals that were denied? 0
d) Avoided CI with danger trees removed (estimate)? ________
e) Avoided CMI with danger trees removed (estimate)? ________

Note 1: Miles cleared in 2013 include total miles of main feeders and laterals and hot spot trimming.
Note 2: NE Division uses GIS system to obtain miles of feeders and laterals.
Note 3: Remaining miles negative numbers indicate additional trimming that the required 3 and 6 year cycles.
Note 4: Vegetation management costs have not been separated between main feeders and laterals.
Note 5: Outage restoration costs have not been historically documented.
Note 6: Distribution is 10 feet and transmission (138KV is 30 feet and 69KV is 15 feet)

NW Division Vegetation Management Performance Metrics – 2013

	Feeders			Laterals		
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.
(A) Number of Outages	1	1	0	226	226	0
(B) Customer Interruptions	1003	1003	0	7,674	7,674	0
(C) Miles Cleared (note 2)	30.68	30.68	0	102.48	102.38	0
(D) Remaining Miles	35	35	0	-156.81	-156.81	0
(E) Outages per Mile [A ÷ (C + D)]	0.02	0.02	0	-4.16	-4.15	0
(F) Vegetation CI per Mile [B ÷ (C + D)]	15.27	15.27	0	-141.25	-140.99	0
(G) Number of Hotspot trims	192	192	0	NA	NA	NA
(H) All Vegetation Management Costs	$559,513	$559,513	0	(Note 4)		
(I) Customer Minutes of Interruption	251,552	251,552	0	517,675	517,675	0
(J) Outage restoration costs	(Note 5)	(Note 5)	NA	NA	NA	NA
(K) Vegetation Budget (current year)	$579,000	$579,000	0	NA	NA	NA
(L) Vegetation Goal (current year)	$579,000	$579,000	0	NA	NA	NA
(M) Vegetation Budget (next year)	$450,000	$450,000	0	NA	NA	NA
(N) Vegetation Goal (next year)	$450,000	$450,000	0	NA	NA	NA
(O) Trim-Back Distance	10	10	NA	10	10	NA

Danger Trees (NW Division) – Additional Questions
a) Number of danger trees removed? 322 (est.)
b) Expenditures on danger tree removal? $40,000 (est)
c) Number of request for removals that were denied? 0
d) Avoided CI with danger trees removed (estimate)? ________
e) Avoided CMI with danger trees removed (estimate)? ________

Note 2: NW Division uses GIS system to obtain miles of feeders and laterals.
Note 4: Vegetation management costs have not been separated between main feeders and laterals.
Note 5: Outage restoration costs have not been historically documented.

NW TREE TRIM SCHEDULE – MAIN FEEDERS

2014 - 2016

2014

1. OCB#9942: HWY 90E Feeder
2. OCB#9992: HWY 90W Feeder
3. OCB#9972 Blountstown Feeder
4. OCB#9882: Bristol Feeder
5. OCB# 9952: Altha Feeder

2015

1. OCB#9932: Indian Springs Feeder
2. OCB#9782 Family Dollar Feeder
3. OCB#9854: South Street Feeder
4. OCB#9512: Railroad Feeder
5. OCB#9872: Hospital Feeder
6. OCB#9752: Industrial Park Feeder

2016

1. OCB#9742: Greenwood/Malone Feeder
2. OCB#9722: Dogwood Heights Feeder
3. OCB#9982: College Feeder
4. OCB#9866: Cottondale Feeder
5. OCB#9732: Prison Feeder

NW TREE TRIM SCHEDULE – LATERALS

2014 - 2019

2014

1. OCB#9882: Bristol Feeder
2. OCB#9972: Blountstown Feeder

2015

1. OCB#9932: Indian Springs Feeder
2. OCB#9942: HWY 90E Feeder
3. OCB#9872: Family Dollar Feeder

2016

1. OCB#9992: HWY 90W Feeder
2. OCB#9854: South Street Feeder
3. OCB#9732: Prison Feeder

2017

1. OCB#9866: Cottondale Feeder
2. OCB#9952: Altha Feeder

2018

1. OCB#9512: Railroad Feeder
2. OCB#9872: Hospital Feeder
3. OCB#9982: College Feeder

2019

1. OCB#9742: Greenwood/Malone Feeder
2. OCB#9722: Dogwood Heights Feeder
3. OCB#9752: Industrial Park Feeder

NE DIVISION - TREE TRIM SCHEDULE – Main Feeders

2014 – 2016

2014:
1. Feeder#310
2. Feeder#311
3. Feeder#201(69KV)
4. Feeder#202 (69KV)
5. Feeder#315 (69KV)

2015:
1. Feeder#102
2. Feeder#104
3. Feeder#110
4. Feeder#111
5. Feeder#802(138KV)
6. Feeder#803(138KV)

2016:
1. Feeder#211
2. Feeder#212
3. Feeder#209
4. Feeder#214
5. Feeder#210
6. Feeder#215
7. Feeder#313 (69KV)

NE DIVISION - TREE TRIM SCHEDULE - Laterals – 2014 – 2019

2014:
1. Feeder#310
2. Feeder#102

2015:
1. Feeder#311
2. Feeder#212

2016:
1. Feeder#214
2. Feeder#215

2017:
1. Feeder#110
2. Feeder#111

2018:
1. Feeder#104
2. Feeder#209

2019:
1. Feeder#210
2. Feeder#211

FPUC NE Division - D&T Vegetation Management*

Feeder #	Main Feeder		Feeder Laterals		Main Feeder		Feeder Laterals		TOTALS	
	OH (feet)	UG (feet)	OH (feet)	UG (feet)	OH (miles)	UG (miles)	OH (miles)	UG (miles)	OH (miles)	UG (miles)
311	27,672	260	52,529	95,681	5.24	0.05	9.95	18.12	15.19	18.17
310	16,080	1,485	32,580	51,837	3.05	0.28	6.17	9.82	9.22	10.10
209	25,423	1,062	22,253	37,236	4.81	0.20	4.21	7.05	9.03	7.25
210	9,990	2,245	27,961	6,700	1.89	0.43	5.30	1.27	7.19	1.69
211	13,992	225	60,222	23,852	2.65	0.04	11.41	4.52	14.06	4.56
212	17,477	110	55,966	8,505	3.31	0.02	10.60	1.61	13.91	1.63
214	14,935	305	22,435	3,491	2.83	0.06	4.25	0.66	7.08	0.72
215	11,264	1,250	14,549	38,850	2.13	0.24	2.76	7.36	4.89	7.59
102	19,249	2,207	37,931	114,746	3.65	0.42	7.18	21.73	10.83	22.15
104	1,438	6,799	0	51,595	0.27	1.29	0.00	9.77	0.27	11.06
110	10,292	0	7,762	163,381	1.95	0.00	1.47	30.94	3.42	30.94
111	10,354	6,020	7,990	90,453	1.96	1.14	1.51	17.13	3.47	18.27
Dist. Totals	**178,166**	**21,968**	**342,178**	**686,327**	**33.74**	**4.16**	**64.81**	**129.99**	**98.55**	**134.15**
69KV Line									**11.45**	
138KV Line									**8.02**	
D&T Totals	**178,166**	**21,968**	**342,178**	**686,327**	**33.74**	**4.16**	**64.81**	**129.99**	**118.02**	**134.15**

* Basis for tracking and managing 2010 and future tree trimming cycles (3 yr. mains and 6 yr. laterals) - Data source is GIS mapping system.

2/16/2011

2013 FPUC NE Division - D&T Vegetation Management**

Feeder #	Main Feeder		Feeder Laterals		Main Feeder		Feeder Laterals		TOTALS	
	OH (feet)	UG (feet)	OH (feet)	UG (feet)	OH (miles)	UG (miles)	OH (miles)	UG (miles)	OH (miles)	UG (miles)
311	14,700	0	16,200	0	2.78	0.00	3.07	0.00	5.85	0.00
310	19,975	0	8,250	0	3.78	0.00	1.56	0.00	5.35	0.00
209	7,500	0	60	0	1.42	0.00	0.01	0.00	1.43	0.00
210	2,200	0	14,850	0	0.42	0.00	2.81	0.00	3.23	0.00
211	31,320	0	23,100	0	5.93	0.00	4.38	0.00	10.31	0.00
212	37,050	0	20,900	0	7.02	0.00	3.96	0.00	10.98	0.00
214	18,100	0	22,100	0	3.43	0.00	4.19	0.00	7.61	0.00
215	18,800	0	7,850	0	3.56	0.00	1.49	0.00	5.05	0.00
102	4,875	0	29,145	0	0.92	0.00	5.52	0.00	6.44	0.00
104	750	0	0	0	0.14	0.00	0.00	0.00	0.14	0.00
110	400	0	0	0	0.08	0.00	0.00	0.00	0.08	0.00
111	2,800	0	0	0	0.53	0.00	0.00	0.00	0.53	0.00
Dist. Totals	**158,470**	**0.00**	**142,455**	**0.00**	**30.01**	**0.00**	**26.98**	**0.00**	**56.99**	**0.00**
69KV Line	7,150	0.00	0	0.00	1.35	0.00	0.00	0.00	0.00	0.00
138KV Line	24,954	0.00	0	0.00	4.73	0.00	0.00	0.00	0.00	0.00
D&T Totals	**190,574**	**0.00**	**142,455**	**0.00**	**36.09**	**0.00**	**26.98**	**0.00**	**56.99**	**0.00**

** 2013 Trim Totals

2/26/20134

FPUC NW Division - D&T Vegetation Management*										
	Main Feeder		Feeder Laterals		Main Feeder		Feeder Laterals		TOTALS	
Feeder #	OH (feet)	UG (feet)	OH (feet)	UG (feet)	OH (miles)	UG (miles)	OH (miles)	UG (miles)	OH (miles)	UG (miles)
9742 Greenwood/ Malone	78,442	0	238,837	5,420	14.86	0.00	45.23	1.03	60.09	1.03
9722 Dogwood Heights	22,492	0	62,410	2,870	4.26	0.00	11.82	0.54	16.08	0.54
9982 College	70,950	0	217,104	24,260	13.44	0.00	41.12	4.59	54.56	4.59
9932 Indian Springs	30,117	0	140,560	38,895	5.70	0.00	26.62	7.37	32.33	7.37
9732 Prison	16,950	0	13,505	14,742	3.21	0.00	2.56	2.79	5.77	2.79
9942 Hwy 90E	67,057	0	259,711	21,503	12.70	0.00	49.19	4.07	61.89	4.07
9992 Hwy 90W	15,096	0	58,897	1,365	2.86	0.00	11.15	0.26	14.01	0.26
9854 South Street	80,724	0	441,570	11,934	15.29	0.00	83.63	2.26	98.92	2.26
9882 Bristol	60,851	0	221,202	4,787	11.52	0.00	41.89	0.91	53.42	0.91
9872 Family Dollar	15,910	365	4,559	2,698	3.01	0.07	0.86	0.51	3.88	0.58
9866 Cottondale	71,809	0	348,188	8,838	13.60	0.00	65.94	1.67	79.54	1.67
9952 Altha	47,917	0	237,241	1,521	9.08	0.00	44.93	0.29	54.01	0.29
9972 Blountstown	32,921	0	70,769	1,562	6.24	0.00	13.40	0.30	19.64	0.30
9512 Railroad	41,251	0	81,053	8,206	7.81	0.00	15.35	1.55	23.16	1.55
9872 Hospital	16,417	0	193,307	1,843	3.11	0.00	36.61	0.35	39.72	0.35
9752 Industrial Park	18,609	0	3,589	1,371	3.52	0.00	0.68	0.26	4.20	0.26
Dist. Totals	**687,513**	**365**	**2,592,502**	**151,815**	**130.21**	**0.07**	**491.00**	**28.75**	**621.21**	**28.82**

* Basis for tracking and managing 2010 and future tree trimming cycles (3 yr. mains and 6 yr. laterals) - Data source is GIS mapping system.
2/16/2011

2013 FPUC NW Division - D&T Vegetation Management**										
	Main Feeder		Feeder Laterals		Main Feeder		Feeder Laterals		TOTALS	
Feeder #	OH (feet)	UG (feet)	OH (feet)	UG (feet)	OH (miles)	UG (miles)	OH (miles)	UG (miles)	OH (miles)	UG (miles)
9742 Greenwood/ Malone	14,160	0	74,880	0	2.68	0.00	14.18	0.00	16.86	0.00
9722 Dogwood Heights	11,280	0	5,760	0	2.14	0.00	1.09	0.00	3.23	0.00
9982 College	19,680	0	122,400	0	3.73	0.00	23.18	0.00	26.91	0.00
9932 Indian Springs	0	0	21,600	0	0.00	0.00	4.09	0.00	4.09	0.00
9732 Prison	16,320	0	2,400	0	3.09	0.00	0.45	0.00	3.55	0.00
9942 Hwy 90E	14,640	0	14,880	0	2.77	0.00	2.82	0.00	5.59	0.00
9992 Hwy 90W	10,320	0	0	0	1.95	0.00	0.00	0.00	1.95	0.00
9854 South Street	12,000	0	55,480	0	2.27	0.00	10.51	0.00	12.78	0.00
9882 Bristol	0	0	3,360	0	0.00	0.00	0.64	0.00	0.64	0.00
9872 Family Dollar	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
9866 Cottondale	44,640	0	227,610	0	8.45	0.00	43.11	0.00	51.56	0.00
9952 Altha	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
9972 Blountstown	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
9512 Railroad	0	0	10,800	0	0.00	0.00	2.05	0.00	2.05	0.00
9872 Hospital	13,680	0	1,920	0	2.59	0.00	0.36	0.00	2.95	0.00
9752 Industrial Park	5,280	0	0	0	1.00	0.00	0.00	0.00	1.00	0.00
Dist. Totals	**162,000**	**0**	**541,090**	**0**	**30.68**	**0**	**102.48**	**0**	**133.16**	**0**

** 2013 Trim Totals
2/13/2014

Initiative #2 – Joint Use Pole Attachment Audit

During 2013, six hundred and eighty four (684) detailed pole loading calculations were performed for FPUC by a contractor as part of the Wood Pole Inspection Program. Poles having remaining strength at or below 67% and poles having 3rd party attachments of ½" or larger in diameter were selected for loading assessment using a contractor supplied computer program called LoadCalc. Span lengths, attachment heights, wire sizes, and 3rd party attachments were included in the loading assessments. Loading assessment reports were supplied to FPUC by the contractor. Poles with loading estimates at or above 110% of design load are automatically included in the FPUC post inspection follow-up plan. FPUC will perform additional load assessment on these poles using PoleForeman. FPUC calculations will be in accordance with the 2007 addition of NESC with 60 mph wind speed. Poles that fail the PoleForeman assessment will be scheduled for replacement. Replacement poles will be designed to comply with storm hardening requirements. The list of replacement poles will be provided to 3rd party attachers so they can give feedback concerning existing or planned attachments that may require increased pole size for added loading. Third party attachers will be notified of the replacement pole locations so their attachments can be transferred. FPUC joined NJUNS (National Joint Use Notification System) during 2009 to facilitate notification of joint use partners.

FPUC has joint use agreements with multiple telecommunication and cable television providers. Some need additional language to add or clarify joint use safety audit instructions. The agreements will be rewritten during 2014 to make sure clearly defined provisions are included for joint use pole attachment safety audits. Audits will be initiated as soon as parties agree to terms for conducting the audits. Data collected during the audits will be analyzed to identify poles that could potentially pose a hazard to public safety. Action will be taken to correct any safety issues discovered during the audit as soon as practical. Priority will be given based upon the severity of the potential hazard. The goal is to conduct a thorough joint use safety audit in accord with terms spelled out in the joint use agreements.

Initiative #3 – Six Year Transmission Structure Inspection Program

Transmission inspections will be completed on all transmission facilities and will include climbing patrols of the 138 KV and 69 KV transmission lines owned by FPUC. This inspection will ensure that all structures have a detailed inspection performed at a minimum of every six years. The inspection will include ninety five (95) 138 KV structures and two hundred and nineteen (219) 69 KV structures. The inspections will ensure that all transmission towers and other transmission line supporting equipment such as insulators, guying, grounding, conductor splicing, cross-braces, cross-arms, bolts, etc structurally sound and firmly attached. Customers who own 69 KV transmission line structures connected to FPUC will be strongly encouraged to complete a similar type inspection. In addition to the six year climbing inspections mentioned above, wood transmission poles are also included in the 8 year wood pole ground-line condition inspection and treatment program.

Substation equipment will also be inspected annually to document the integrity of the facility and identify any deficiencies that require action. Substations will be inspected to ensure that all structures, buss work, insulators, grounding, bracing, bolts, etc are structurally sound and firmly attached.

Transmission Circuit, Substation and Other Equipment Inspections

	Activity		Current Budget**		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Total transmission circuits.	19.5	19.5	NA	NA	19.5	NA
(B) Planned transmission circuit inspections ***	19.5	19.5	NA	NA	19.5	NA
(C) Completed transmission circuit *** inspections.	19.5	19.5	NA	NA	19.5	NA
(D) Percent of transmission circuit inspections completed. *	100%	100%	NA	NA	100%	NA
(E) Planned transmission substation inspections	4	4	NA	NA	4	NA
(F) Completed transmission substation * inspections.	4	4	NA	NA	4	NA
(G) Percent transmission substation inspections completed.*	100%	100%	NA	NA	100%	NA
(H) Planned transmission equipment inspections (other equipment).	NA	NA	NA	NA	NA	NA
(I) Completed transmission equipment inspections (other equipment).	NA	NA	NA	NA	NA	NA
(J) Percent of transmission equipment inspections completed (other equipment).	NA	NA	NA	NA	NA	NA

* Inspections performed were visual
** Current accounting system does not provide data to this level
*** 6 yr. climbing inspection completed in 2012

Transmission Tower Structure Inspections

	Activity		Current Budget**		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Total transmission tower structures.	4	4	NA	NA	4	NA
(B) Planned transmission tower structure Inspections *	4	4	NA	NA	4	NA
(C) Completed transmission tower structure inspections. *	4	4	NA	NA	4	NA
(D) Percent of transmission tower structure inspections completed.	100%	100%	NA	NA	100%	NA

* Inspections performed were visual
** Current accounting system does not provide data to this level

Transmission Pole Inspections

	Activity		Current Budget		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Total number of transmission poles. *	297	297	NA	NA	NA	NA
(B) Number of transmission poles strength tested.	NA	NA	NA	NA	NA	NA
(C) Number of transmission poles passing strength test.	NA	NA	NA	NA	NA	NA
(D) Number of transmission poles failing strength test (overloaded).	NA	NA	NA	NA	NA	NA
(E) Number of transmission poles failing strength test (other reasons).	NA	NA	NA	NA	NA	NA
(F) Number of transmission poles corrected (strength failure).	NA	NA	NA	NA	NA	NA
(G) Number of transmission poles corrected (other reasons).	NA	NA	NA	NA	NA	NA
(H) Total transmission poles replaced.	NA	NA	NA	NA	NA	NA

*FPUC includes wood transmission poles in the eight year ground-line condition inspection and treatment program.

Initiative #4 – Storm Hardening of Existing Transmission Structures

NE Division's 138 KV transmission system was constructed using concrete poles, steel poles, and steel towers. The construction generally complies with storm hardening requirements. The structures will continue to be inspected as outlined in Initiative #3 - Six Year Transmission Structure Inspection Program to ensure the integrity of the system.

The 69 KV transmission system consists of a total of 219 poles of which 43 are concrete poles. All installations met the NESC code requirements in effect at the time of construction. A policy of replacing existing wood poles with concrete has been in place for some time. This policy requires that when it becomes necessary to replace a wood pole due to construction requirements or concerns with the integrity of the pole, a concrete pole that meets current NESC codes and storm hardening requirements will be utilized.

There was no storm hardening projects performed on transmission poles or structures during 2013. However, in 2012 the NE division conducted the six year transmission climbing inspection outlined in initiative #3. There were 31 wooden transmission poles identified for replacement. In 2013 two additional poles were added for replacement bringing the total to 33 poles. A project plan was developed to replace these poles. The poles will be replaced with concrete transmission structures during the beginning of 2014.

NW Division currently has no transmission structures.

Hardening of Existing Transmission Structures

	Activity		Current Budget		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Transmission structures scheduled for hardening.	**0**	**0**	**0**	**0**	**0**	**0**
(B) Transmission structures hardening completed.	**0**	**0**	**0**	**0**	**0**	**0**
(C) Percent transmission structures hardening completed.	**0**	**0**	**0**	**0**	**0**	**0**

Initiative #5 – Geographic Information System

FPUC has a GIS mapping system for both divisions. The systems are ESRI based using ArcGIS to identify the distribution and/or transmission facilities overlaid on a GIS land base. The systems locate the facilities on the land base and allow the users to enter data updates for all existing or new physical assets within the system. The system has proven to be a reliable and valuable tool for the engineering of new construction or existing system maintenance projects.

The system also interfaces with the Customer Information System to function as a Customer Outage Management System (OMS). Implementation of the OMS has resulted in significant improvement in data collection and retrieval capability for analyzing and reporting reliability indices.

The GIS is being used as an integral part of the data collection for many of the programs mentioned in this update. The information, now available in the GIS, will be instrumental in conducting future pole inspections and joint use audits. In addition, the OMS will serve as a valuable tool for use in post storm forensic analysis.

In 2013 FPUC completed the upgrade and installation of a new GIS mapping system which has integrated multiple utility systems (gas, electric, propane, etc) into one system. The migration of data began in 2012 and was completed by the end of 2013. In addition, a new and improved version of the OMS system was also installed in 2013. This OMS will be further enhanced in 2014 to enable customer outage calls to be automatically logged into the system. There is a potential for a temporary setback in the quality and timeliness of data collection during the transition.

Initiative #6 - Post-Storm Data Collection and Forensic Analysis

FPUC has established a forensics oversight team to coordinate communications, schedule data collection activities, and final reporting requirements. Our plans are to utilize a consultant, Osmose Utility Services, to collect, analyze, and report on field data collected which will be entered into the FPUC Outage Management System (OMS). FPUC will utilize standard reporting forms for submitting forensic data to the FPSC.

The following is a copy of the FPUC "FORENSIC DATA COLLECTION AND REPORTING" procedure:

FORENSIC DATA COLLECTION AND REPORTING

PURPOSE:

To set standards and responsibilities for the collection, assessment, and reporting of storm related damage to FPUC transmission, substation, and distribution structures and equipment. To accomplish these tasks in an orderly manner, safely, and with a minimum of interference with the process of system restoration following a storm.

PROCESS:

A minimum of 72 hours prior to the storm; FPU will initiate the forensic process by alerting team members both in-house and external of the impending event. All contact information will be verified for accuracy and all equipment will be checked to make sure it is in good working order.

48 hours prior to the storm; begin the process of accessing where the storm is most likely to strike and determine the best locations for forensic teams. Inform team members of more specific information as it becomes available.

24 hours prior to the storm; notify all team members of actual crew personnel, mobilization plan, safety procedures, and reporting instructions.

After the storm; perform a forensic investigation at each location encountered that meets reportable criteria. Damage locations to include, but are not limited to poles, wires, crossarms, insulators, transformers, reclosers, capacitor banks, cutouts, any other equipment that is damaged or has caused a customer outage.

Damage areas will be determined and teams dispatched utilizing FPU's outage management system, reports from customers, and reports from restoration crews.

RESPONSIBILITIES:

An FPUC Forensic Team Leader will be assigned and will be responsible for managing the overall forensic effort. This will include tracking storm progress, coordinating team deployment, communication with local ERT Centers, review findings, and generating final reports.

Florida Public Utilities Company will utilize Osmose Utility Services to provide forensic investigative teams that will be responsible for safely collecting information on storm damage. Damaged facilities are defined as broken poles, leaning poles, broken or downed wires, damaged line equipment, and any other incident that has caused a customer outage.

REPORTING:

All post storm forensic data collected will be entered in standard forms. The form allows both overhead and underground damage to be entered and data must be entered separately for each incident. Pictures of damages from multiple views will be taken and included for clarity and additional assessment.

Initiative #7 – Reliability Performance of Overhead vs Underground Systems

FPUC collects outage data attributed to overhead or underground equipment failure in order to evaluate the associated reliability indices. OH & UG adjusted reliability indices are reported for each Division and for FPUC system total.

During 2013, there were no projects in the NE Division to convert overhead facilities to underground However, the local government approached FPUC to discuss undergrounding some of the overhead facilities associated with the storm hardening projects planned for construction during 2012. FPUC agreed to take another look at the projects as soon as the local government officials made a formal request for preliminary cost estimates. As of the end of 2013, no formal request was received by FPUC. The two NE Division storm hardening projects submitted in the FPUC 2010-2012 Storm Hardening Plan have been placed on hold pending input from local government. Two new storm hardening projects are under development for the NE Division and were included in the FPUC 2013-2015 Storm Hardening Plan.

During 2013 there was no OH to UG conversions in the NW Division. However, two storm hardening projects took place in the NW division. Distribution facilities along Hartsfield Rd were relocated along the county ROW and storm hardened in the process. The Malone feeder between Greenwood and Malone began at the end of 2013 and will be complete mid-2014.

2013 - Reliability Indicators By UG & OH - FPUC Total (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
OH	1,102	6.75	86.37	157,271	1,821	7,438		
UG	22	54.03	104.83	20,127	192	1,189		
	1124	7.67	88.13	177,398	2,013	8,627	6.31	0.07

Total No. of Customers at end of 2013 ==> **28,111**

2013 - Reliability Indicators By (OH) - FPUC NE (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
102 South Fletcher	18	118.15	109.48	76,419	698	2,127		
110 Plantation Roadside	1	138.25	138.25	138	1	138		
111 Plantation Fieldside	1	54.57	54.57	546	10	55		
209 Fifteenth Street	7	78.74	92.50	6,845	74	551		
210 Buss Tie	8	103.81	139.26	432,830	3,108	831		
211 Jasmine Street	9	98.21	97.18	72,110	742	884		
212 Eleventh Street	17	109.01	53.60	276,041	5,150	1,853		
214 Clinch Drive	24	97.16	72.19	24,473	339	2,332		
215 Sadler, Nectarine, So.14th	13	88.48	66.28	7,291	110	1,150		
310 Bonnieview	7	96.58	46.46	44,228	952	676		
311 Bailey	9	70.33	69.16	20,332	294	633		
	147	98.60	80.76	1,169,821	14,486	14,495	75.43	0.93

Total No. of Customers at end of 3==> **15,509**

2013 - Reliability Indicators By (UG) - FPUC NE (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
102 South Fletcher	2	35.23	13.84	1,190	86	70		
110 Plantation Roadside	2	69.16	58.52	293	5	138		
111 Plantation Fieldside	1	396.15	396.15	1,188	3	396		
209 Fifteenth Street	1	50.43	50.43	50	1	50		
210 Buss Tie	1	117.55	117.55	118	1	118		
211 Jasmine Street	5	188.87	240.34	2,644	11	944		
215 Sadler, Nectarine, So.14th	1	26.00	26.00	1,300	50	26		
310 Bonnieview	1	99.93	99.93	100	1	100		
311 Bailey	5	160.46	112.37	9,664	86	802		
	19	139.24	67.81	16,547	244	2,646	1.07	0.02

Total No. of Customers at end of 2013 ==> **15,509**

2013 - Reliability Indicators By (OH) - FPUC NW (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
Altha	71	104.76	86.37	157,271	1,821	7,438		
Blountstwn	12	99.06	104.83	20,127	192	1,189		
Bristol	63	60.81	49.44	94,029	1,902	3,831		
College	119	89.24	67.74	295,810	4,367	10,619		
Cottondale	121	85.50	96.88	605,623	6,251	10,345		
Dogwood Ht	23	66.21	69.14	14,934	216	1,523		
Family Dol	1	69.30	69.30	69	1	69		
Greenwood	128	96.55	141.17	877,683	6,217	12,358		
Hospital	41	108.91	127.31	193,643	1,521	4,465		
Hwy 90e	83	82.77	121.48	165,212	1,360	6,870		
Hwy 90w	25	106.82	87.73	33,512	382	2,671		
Ind Park	2	159.46	227.38	10,459	46	319		
Indian Spr	80	90.64	80.21	107,161	1,336	7,251		
Prison	6	80.22	96.65	1,063	11	481		
Railroad	35	93.20	132.12	512,242	3,877	3,262		
South St	145	88.78	70.58	482,381	6,835	12,873		
	955	89.60	98.29	3,571,222	36,335	85,565	283.39	2.88

Total No. of Customers at end of 2013 ==> **12,602**

2013 - Reliability Indicators By (UG) - FPUC NW (Adjusted)

Cause	Number of Outage Events (N)	Average Duration (L-Bar)	CAIDI	Sum of all Customer Min. Interrupted (CMI)	Total Customer Interruptions (CI)	Total Outage Duration (L)	SAIDI	SAIFI
College	1	199.67	199.67	4,393	22	200		
Indian Spr	1	326.83	326.83	7,190	22	327		
Railroad	1	145.73	145.73	146	1	146		
	3	224.08	260.64	11,729	45	672	0.93	0.00

Total No. of Customers at end of 2013 ==> **12,602**

Initiative #8 – Utility Company Coordination with Local Governments

FPUC actively participates with local governments in pre-planning for emergency situations and in coordinating activities during emergency situations. Current practice is to have FPUC personnel located at the county EOC's on a 24 hour basis during emergency situations to ensure good communications.

FPUC has continued involvement with local governments regarding reliability issues with emphasis on both undergrounding and vegetation management. All parties have continued to cooperate in order to address vegetation management issues in a cost effective manner when possible so that overall reliability impacts are minimized.

FPUC and the City of Marianna have worked together to complete a project of undergrounding in the downtown area of Marianna and are planning further projects. Although these projects have improved aesthetics as the major goal, they will provide a reliability case study area that can be used in future undergrounding analysis.

Initiative #9 – Collaborative Research

FPUC is participating with the Public Utility Research Center (PURC) along with other investor owned, cooperative, and municipal electric utilities in order to perform beneficial research regarding hurricane winds and storm surge within the state. PURC has demonstrated the ability to lead and coordinate multiple groups in research activities. FPUC will continue to support this effort but does not intend to conduct any additional research at this time.

The benefits of the research work among the utilities and PURC include increased and sustained collaboration and discussion among the members of the Steering Committee, greater knowledge of the determinants of damage during storm and non-storm times, greater knowledge and data from wind collection stations and post-hurricane forensics in the State of Florida, and continued state-to-state collaboration with others in the Atlantic Basin Hurricane Zone.

For 2013, research focused on undergrounding, wind data collection, and public outreach. The Steering Committee is preparing the next steps in these research areas.

The 2014 report follows on the next page.

Report on Collaborative Research for Hurricane Hardening

Provided by

The Public Utility Research Center
University of Florida

To the

Utility Sponsor Steering Committee

February 2014

I. Introduction

The Florida Public Service Commission (FPSC) issued Order No. PSC-06-00351-PAA-EI on April 25, 2006 (Order 06-0351) directing each investor-owned electric utility (IOU) to establish a plan that increases collaborative research to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers. This order directed IOUs to solicit participation from municipal electric utilities and rural electric cooperatives in addition to available educational and research organizations. As a means of accomplishing this task, the IOUs joined with the municipal electric utilities and rural electric cooperatives in the state (collectively referred to as the Project Sponsors) to form a Steering Committee of representatives from each utility and entered into a Memorandum of Understanding (MOU) with the University of Florida's Public Utility Research Center (PURC). This MOU was recently extended by the Research Collaboration Partners through December 31, 2015.

PURC manages the work flow and communications, develops work plans, serves as a subject matter expert, conducts research, facilitates the hiring of experts, coordinates with research vendors, advises the Project Sponsors, and provides reports for Project activities. The collaborative research has focused on undergrounding, vegetation management, hurricane-wind speeds at granular levels, and improved materials for distribution facilities.

This report provides an update on the activities of the Steering Committee since the previous report dated February 2013.

II. Undergrounding

The collaborative research on undergrounding has been focused on understanding the existing research on the economics and effects of hardening strategies, including undergrounding, so that informed decisions can be made about undergrounding policies and specific undergrounding projects.

The collaborative has refined the computer model developed by Quanta Technologies and there has been a collective effort to learn more about the function and functionality of the computer code. PURC and the Project Sponsors have worked to fill information gaps for model inputs and significant efforts have been invested in the area of forensics data collection. Since the state has not been affected by any hurricanes since the database software was completed, there is currently no data. Therefore, future efforts to refine the undergrounding model will occur when such data becomes available.

In addition, PURC has worked with doctoral and master's candidates in the University of Florida Department of Civil and Coastal Engineering to assess some of the inter-relationships between wind speed and other environmental factors on utility equipment damage. PURC has also been contacted by engineering researchers at other universities with an interest in the model, though no additional relationships have been established. In addition to universities, PURC was contacted by researchers at the Argonne National Laboratory who expressed interest in modeling the effects of storm damage. The researchers ultimately chose to develop a deterministic model, but did use many of the factors that the Collaborative have attempted to quantify. Every researcher that contacts PURC cites the model as the only non-proprietary model of its kind.

The research discussed in last year's report on the relationship between wind speed and rainfall is still under review by the engineering press. Further results of this and related research can likely be used to further refine the model.

III. Wind Data Collection

The Project Sponsors entered into a wind monitoring agreement with WeatherFlow, Inc., in 2007. Under the agreement, Florida Sponsors agreed to provide WeatherFlow with access to their properties and to allow WeatherFlow to install, maintain and operate portions of their wind monitoring network facilities on utility-owned properties under certain conditions in exchange for access to wind monitoring data generated by WeatherFlow's wind monitoring network in Florida. WeatherFlow's Florida wind monitoring network includes 50 permanent wind monitoring stations around the coast of Florida, including one or more stations located on utility-owned property. The wind monitoring agreement expired in early 2012; however, the wind, temperature, and barometric pressure data being collected at these stations is being made available to the Project Sponsors on a complimentary basis.

IV. Public Outreach

In last year's report we discussed the impact of Hurricane Sandy on greater interest in storm preparedness. PURC researchers discussed the collaborative effort in Florida with the engineering departments of the state regulators in Pennsylvania, Maryland, New York, and New Jersey. While all of the regulators and policymakers showed great interest in the genesis of the collaborative effort, and the results of that effort, they have not, at this point, shown further interest in participating in the research effort.

On April 15, 2013, the *Wall Street Journal* published a special section entitled 'Big Issues: Energy' which featured authors promulgating the "Yes" or "No" position to various questions surrounding the energy industry. One of those questions was "Should Utilities Be Required to Bury Power Lines to Protect Them?", and the editors of the *Journal* asked PURC Director of Energy Studies Ted Kury to contribute the "No" position. In October, Kury and Dr. Roger Anderson of Columbia University (who had provided the "Yes" position), revisited their print debate as the keynote session of the 2013 EEI/NRECA Utility Siting Workshop in Richmond, Virginia.

V. Conclusion

In response to the FPSC's Order 06-0351, IOUs, municipal electric utilities, and rural electric cooperatives joined together and retained PURC to coordinate research on electric infrastructure hardening. The steering committee has taken steps to extend the research collaboration MOU so that the industry will be in a position to focus its research efforts on undergrounding research, granular wind research and vegetation management when significant storm activity affects the state.

Initiative #10 – Natural Disaster Preparedness and Recovery Program

FPUC will utilize the plan to prepare for storms annually and will ensure all employees are aware of their responsibilities The primary objective of the Disaster Preparedness and Recovery Plan is to provide guidelines under which Florida Public Utilities Company will operate in emergency situations. This information is contained with the Emergency Procedures that are updated on an annual basis, if required. The following objectives are included to ensure orderly and efficient service restoration.

1. The safety of employees, contractors and the general public will have the highest priority.
2. Early damage assessment is required in order to develop manpower requirements.
3. Request additional manpower as soon as conditions and information indicate the need.
4. Provide for orderly restoration activities in order to provide efficient and rapid restoration.
5. Provide all logistical needs for employees and contractors.
6. Provide ongoing preparation of our employees, buildings, equipment and support function in advance of an emergency.
7. Provide support and additional resources for employees and their families should they need assistance to address injury or damage as a result of the emergency situation.

Based on the location of the storm, the division office in that area will be designated as the operations center and all restoration and logistical activities will be coordinated from that location. Restoration activities will be handled in the following manner:

1. During the early stages of the emergency, restoration will be handled in the usual manner. All service will be restored as soon as possible.
2. As the storm intensifies and trouble reaches major proportions, the main restoration activities will be limited to keeping main feeders energized by clearing trouble without making repairs.
3. When the intensity of the storm is such that work can no longer be done safely, all work will cease and personnel will report to the office or other safe locations.
4. When the storm has subsided to a reasonable level and it is safe to begin restoration activities damage assessment and restoration of main feeders to critical customers will begin.
5. Restoration activities will continue in an effort to restore service in the following manner:

    a) Substations
    b) Main feeders to critical customers
    c) Other main feeders
    d) Undamaged primary
    e) Damaged primary, secondary, service, street lights, security lights

These guidelines are not intended to prevent responding to emergency situations. Any life threatening emergency will be handled immediately, in such a manner as to not endanger the lives of others.

Communication efforts with local governments, County EOC's and the media will be a key in ensuring a safe and efficient restoration effort. Key personnel will be designated as the media liaison and will ensure that communications regarding the status of the restoration activities are available on a scheduled basis.

Emergency Procedures for both divisions were updated during 2014 and are included in this section of the report.

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

2014
EMERGENCY PROCEDURES

1. Objective

The primary objective of the procedure is to provide guidelines under which the Northwest Florida Division of Florida Public Utilities Company will operate in emergency conditions. The following objectives will ensure orderly and efficient service restoration.

A. The safety of employees, contractors and the general public will have the highest priority.

B. Early damage assessment is required in order to develop manpower requirements.

C. Request additional manpower as soon as conditions and information indicate the need.

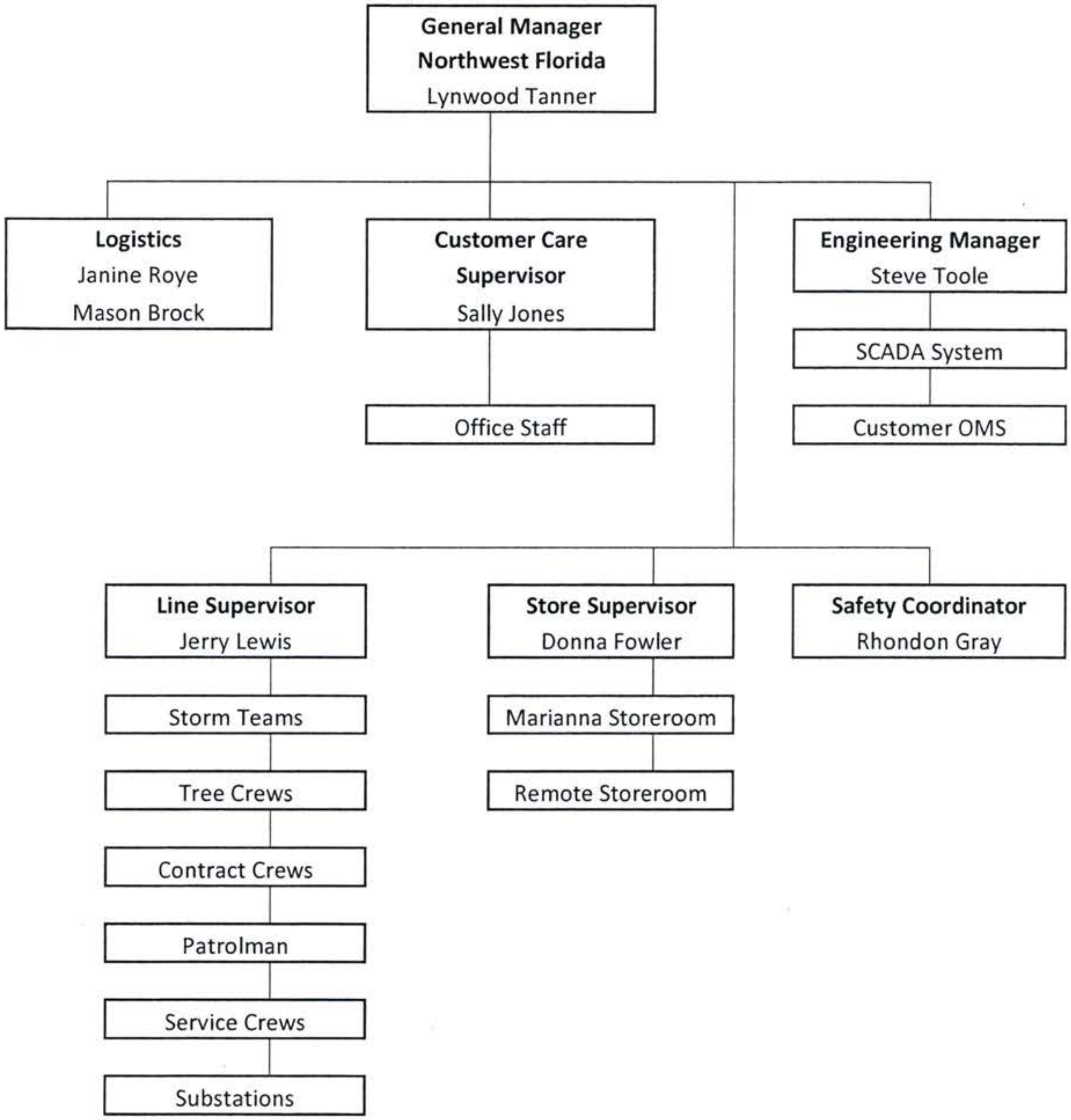
D. Provide for orderly restoration activities in order to provide efficient and rapid restoration.

E. Provide all logistical needs for employees and contractors.

F. Provide ongoing preparation of our employees, buildings, equipment and support function in advance of an emergency.

G. Provide support and additional resources for employees and their families should they need assistance to address injury or damage as a result of the emergency situation.

1. **ORGANIZATIONAL CHART**



3. EMERGENCY PERSONNEL POLICY

As a public utility we provide essential services for our customers and the general public. Therefore, the purpose of the Company's Emergency Personnel Policy is to encourage employees to make every reasonable effort to report to work. Each employee performs an essential role in the Company's operation and it's important that you report to duty as scheduled during an emergency. Restoring and maintaining services after a major storm is a difficult job and requires everyone's best efforts. Of necessity, employees may be required to assist other departments or perform functions outside of their normal daily work assignment. It will take every employee's cooperation before, during and after an emergency.

A. If you are on the job when the storm approaches, your supervisor will inform you of your storm assignment. Employees not directly involved in maintaining services may be released to go home before the storm threatens safe travel.

B. If you are off-duty, call your immediate supervisor as soon as possible after an emergency condition is announced. An Emergency Condition Warning is usually given within 24 hours of occurrence. Your supervisor will inform you as to where and when you'll be needed prior to, during, and after the storm. If your supervisor is not available call his/her immediate supervisor or the Northwest Florida Office. This requirement applies to all electric division employees when an emergency threatens any of the Company's electric service area.

C. During an emergency, the company will maintain a small workforce to monitor the emergency and address emergency conditions that may exists. This workforce will be located at a safe location and work closely with the Counties served EOCs. The company will determine what workforce is required and will consider utilizing those employees who volunteer for this type of work. The General Manager, Engineering Manager, Line and Service Supervisors will form the basis of this group. Other employees will be included based on the severity and timing of the emergency.

D. All employees are strongly encouraged to have a personal evacuation plan and know what to do during an emergency condition that impacts the service area. The plan should take into consideration the magnitude of the emergency and the significance of the actions that may be necessary. The plan should ensure that the employee and their family are safely out of harm's way while still allowing the employee to respond as required when the emergency conditions subside to a manageable level.

E. The company plans to move much of the transportation equipment to separate locations to ensure one event does not cause damage to the fleet. Employees are encouraged to volunteer to take certain vehicles with them prior to the emergency and use them to return to work as soon as possible after the emergency conditions subside to a manageable level. The company will determine how the transportation equipment is distributed among the volunteer employees.

F. After the emergency passes, all personnel not on duty during the storm will report as soon as possible to their supervisor or his/her designate by telephone. In the event the telephones are not working or you are unable to communicate with your supervisor or the company office, report in person to your regular work station as soon as possible during daylight hours.

G. EMPLOYEES ARE TO MAKE EVERY REASONABLE EFFORT TO REPORT TO WORK. IT'S UNDERSTOOD THAT THERE WILL BE INSTANCES WHERE EMPLOYEES JUST CAN'T GET TO WORK. IF YOU ARE UNABLE TO REPORT TO WORK MAKE EVERY EFFORT TO CONTACT YOUR SUPERVISOR TO REPORT YOUR ABSENCE.

H. Personal emergencies are a common result of a major hurricane, but unless approved by your Supervisor, will not be acceptable as an excuse for not reporting to work. Evacuation from a hurricane threatened area to a remote location from which you cannot promptly return to your home is also not acceptable as a reason for not reporting to work.

I. The Company will endeavor to provide assistance and shelter to employees and their immediate families should an employee need or request assistance.

J. Unless emergency conditions warrant, employees will not be required to work in excess of sixteen (16) consecutive hours.

The success of the emergency plan requires the cooperation and efforts of all of our employees. Employees may be required to return from their vacation or Company sponsored travel. Therefore, it will be the responsibility of each supervisor to determine the location of each of their employees on Company sponsored trips to facilitate their recall if conditions warrant their return when the emergency plan is implemented. Employees who are on vacation will notify, by telephone, their supervisors of their location and availability when an emergency threatens to strike our service area. Supervisors will consult with their department head to determine the feasibility and need to recall employees from vacation or Company sponsored trips. All employees are essential for the continued operation of the Company obligations and Company objectives.

The Company will develop information which will assist employees and their families before, during and after the storm. The General Manager, Northwest Florida will be responsible for obtaining the information and communicating this information to the employees. The Company will attempt to provide assistance to the employees and their families during emergency situations if needed.

4. GENERAL RESTORATION GUIDELINES

These general guidelines are issued to provide overall guidance as to emergency system restoration activities. These guidelines will be followed as much as practical in emergencies caused by hurricanes, tornadoes, ice storms and other natural disasters.

These guidelines are not intended to nor will they put in jeopardy the safety of any employee or their family. Dependent upon the intensity of the storm as determined by the company's management, employees will be required to report to work as instructed. If the intensity of the storm is such that weather conditions will be extremely severe, only a skeleton crew will be present at the work location. All others will report for duty as soon as conditions subside to a reasonable level. Those on vacation will be expected to report for duty.

The Northwest Florida office building was designed to withstand 100 mph sustained winds. Should winds be expected to significantly exceed these ratings, alternative locations will be identified and restoration activities will be relocated to an appropriate facility.

Restoration activities will be handled in the following manner:

A. During the early stages of the emergency, restoration will be handled in the usual manner. All service will be restored as soon as possible.

B. As the storm intensifies and trouble reaches major proportions, the main restoration activities will be limited to keeping main feeder energized by clearing trouble without making repairs.

C. When the intensity of the storm is such that work can no longer be done safely, all work will cease and personnel will report to the office or other safe location.

D. When the storm has subsided to a reasonable level and it is safe to begin restoration activities damage assessment and restoration of main feeders to critical customers will begin.

E. Restoration activities will continue in an effort to restore service in the following manner:
   1) Substations
   2) Main feeders to critical customers
   3) Other main feeders
   4) Undamaged primary
   5) Damaged primary, secondary, service, street lights, security lights

These guidelines are not intended to prevent responding to emergency situations. Any life threatening emergency will be handled immediately, in such a manner as to not endanger the lives of others.

Each employee and contractor should maintain good customer relations during restoration activities. Customer service will continue to be a high priority and every reasonable effort should be made to satisfy our customers.

Press releases and public announcements should be made only by designated company management personnel.

5. Emergency Safety Precaution

All Rules in the Safe Practices Manual Should be Observed. However, in order to point out some particular precautions which should be observed during storms, the following instructions listed below should receive special emphasis:

A. SIZING UP WORK:

Before undertaking any job, the job should be thoroughly discussed and all personnel should understand what is to be done, how it is to be done, and the following:

1) Voltage and position of all wires, or cables, and the sources or source of energy.
2) That the work in hand can be done safely.
3) That there is a sufficient amount of each kind of protective equipment on hand to thoroughly protect the working position and the work man.
4) They should consider the ground and traffic conditions and arrange to protect and guard these against all hazards.

B. INSULATION:

In cases of trouble following storms, all wires, regardless of normal voltage, are to be considered as being at primary voltage and are not to be handled except with protective equipment because of the danger of crosses between primary and secondary circuits.

C. DISTRIBUTION CIRCUITS ON OR NEAR TRANSMISSION POLES:

If it is necessary to work on the conductors of a distribution circuit carried on or near transmission line poles with the transmission circuit energized and normal, any work on the conductors of the distribution circuits must be done between sets of grounds or else the distribution circuit must be worked and treated as an energized circuit. To determine positively that the lines to be worked are de-energized, test or investigation must be made before grounds are applied.

If the transmission line is also out of service and apparently in trouble, it must be considered as a possible source from which the distribution circuit may be energized, and it must be definitely determined that the transmission circuit as well as the distribution circuit is de-energized and grounded and the source or sources of supply are open and proper clearance obtained before the distribution circuit may be worked as de-energized.

D. STREET LIGHTING WIRES:

Street lighting wires shall be considered energized at all times and the workman shall protect himself against them with proper protective equipment even when circuits are normally de-energized. Such a line is liable to become energized by accidental induction or lightning and sometimes street lighting wires become crossed with other energized wires.

E. FUSE CUT-OUT CLEARANCE:

When a distribution circuit is to be de-energized and cleared for working on conductors or other equipment by the opening of a fuse cut-out, either of the enclosed or open type, the fuse holder or tube is to be removed completely from the fuse assembly. The removed fuse holder or tube is to be placed at a safe and conspicuous location away from the fuse cut-out as an indication to other employees that the fuse cut-out shall continue in this open position until the work is completed. In addition, a red "hold" switch tag (with Lineman's name) should be attached to the pole in a conspicuous location and then removed when work is completed.

F. REQUIREMENTS FOR USE OF RUBBER PROTECTIVE APPARATUS:

In case of trouble following storms, all wires, regardless of normal voltage, are to be considered as being at primary voltage and are not to be handled except with protective equipment because of danger of crosses between primary and secondary circuits.

1) Energized Conductors - Rubber gloves must always be worn when working on energized lines or energized conductors or equipment up to 15,000 volts between conductors.

2) Working position - Rubber gloves must be put on before coming in reach of energized conductors when work is done on conductors or protective equipment is to be installed.

Because of the possibility of high voltage existing, rubber gloves must be worn until the conductor is grounded on primary circuits and on street lighting circuits.

Care of Rubber Protective Apparatus - At each job, before a workman puts on his rubber gloves, he should test each glove mechanically for cuts and weak spots by rolling it up tightly, beginning at the gauntlet. All of this type equipment, when not in use, must be stored in dry proper containers or compartment provided for this purpose.

G. SWITCHING ORDERS:

In all switching orders, the switches shall be referred to by their numbers and not by the name of the circuit which they control. The sequence in which the switch numbers are given, in the order, shall indicate the sequence of the switching operation. For example, an order given: "open switches 502-509 and close switches 511-502" shall be executed as follows: first, open switch 502; second, open switch 509; third, close switch 511; fourth, close switch 502.

NO DEVIATION FROM THIS RULE WILL BE PERMITTED.

To avoid misunderstandings and to prevent accidents, all orders concerning switching operations, or the handling of lines and equipment must be repeated to the person giving name, and identity of person giving order secured. Likewise, the operator giving an order must secure identity of person to whom it is given.

H. SWITCHING ORDER:

All switching orders must be written on a piece of paper by the person receiving same, and this written order must be carried by the person while doing the switching. ***In no case shall anyone attempt to execute a switching order from memory.***

I. HIGH WATER:

During periods of high water involving lines or equipment, patrolmen shall not attempt to swim sections of the patrol which may be submerged. Necessary patrols over flooded areas must be done with boats and in such instances men engaged in these patrols shall wear suitable life belts or jackets.

J. BROKEN CONDUCTORS:

Before climbing pole, check for broken conductors which may be in contact with pole. Clear before climbing.

6. Annual Preparations

General Manger, Northwest Florida

A. Review emergency procedure prior to May 1 and update as necessary.

B. Review employee assignments with all personnel prior to June 1.

C. Update status of emergency crew assistance (Contractors, NW Florida, SEE, Gulf Power, WFEC, etc.).

D. Schedule and conduct half day emergency procedure training sessions prior to July 1.

E. Ensure storm shutters, laundry facilities and cooking facilities are available.

Engineering Manager

A. Check all communication equipment for proper operation. Check spare equipment and parts.

B. Check material quantities and emergency stock prior to June 1. Begin necessary purchasing of emergency stock approved for purchase prior to an emergency.

C. Update and have on hand the following:

1) Storm safety precautions
2) General operating instructions
3) Distribution maps
4) Single line switching maps
5) City and county maps

D. Have necessary emergency material delivered prior to June 1.

Logistics

A. Update the list of critical customers by town/county. Group the critical customers by town/county by classification:

1) Hospitals and clinics
2) Public utilities
3) Municipal and state emergency service
4) Communication and broadcasting services
5) Major food storage/processing facilities
6) Disaster shelter and motels
7) Correctional facilities
8) Airport

B. Update phone list for employees, law enforcement, emergency management, city/towns, utilities, contractors, tree trimming, personnel, news media, PSC, DCA, EDC, GEO, etc.

C. Review emergency telephone arrangements and make additional preliminary arrangements.

D. Have "Emergency Vehicle" cards for vehicles.

E. Update status of thirty (30) motel rooms necessary for emergency/contract crews.

F. Locate sources of food/water for crews and office personnel. Identify local and out of town caterers.

G. Update status of building security firm.

H. Locate sources for provision of the following Division office supplies.

1) Three day supply of food and water. (See section 22, Logistics for List of Supplies)
2) Supply of air mattress/cots.
3) Portable AM/FM radios with batteries.
4) Laundry services/supplies.
5) First aid supplies.
6) Twenty (20) flashlights with batteries.
7) Linen service.
8) Miscellaneous supplies post storm shelter

I. Update the procedure of the Lockbox Operation.

Line and Service Supervisors

A. Review safety precautions with all line crew personnel prior to June 1.

B. Have control room and all necessary information and equipment ready for prompt setup. Phone jacks, radio transmitter connection and distribution map are minimum requirements.

C. Conduct annual refresher training for personnel required to operate the SCADA System and Customer Outage System.

D. Review status of all transportation equipment and have repairs made.

E. Update status of remote storeroom site and trailer(s).

F. Update status of emergency fuel suppliers, on site fuel and mobile fuel suppliers.

G. Update status of vehicle repair facilities

General Manager, Northwest Florida

A. Monitor the emergency.

B. Begin making preparations for obtaining emergency assistance from other utilities and contractors.

C. Check the status of personnel on vacation.

D. Handle all media request.

E. Inform all employees as to assignments and emergency information.

F. Consult with FPUC President concerning activation of Division Emergency Procedures.

G. Consult with Senior Staff concerning assistance from other divisions (i.e. mechanics, storeroom, media, family assistance, IT/Communications. Personnel from other divisions will be identified and mobilized. They will move as close as practical to Northwest Florida and then proceed to the office as soon after the emergency as travel can be accomplished safely. This location may change dependant upon the situation.

H. Obtain special job number for all emergency related work.

Line and Service Supervisors

A. Have all vehicles stocked with all necessary emergency materials and fuel.

B. Check emergency stock levels and fuel supplies.

C. Review plan to supply power to office and warehouse facility.

D. Check all communication equipment.

E. Review safety precautions with all personnel.

F. Review line department job assignments with personnel and pass out necessary forms, information.

G. Have all hazardous conditions corrected and construction jobs stabilized.

H. Verify emergency generator is fully fueled and operable with back-up fuel available.

I. Make arrangements for a boat and trailer suitable for construction.

J. Ensure all vehicle repairs are made and final arrangements with vehicle repair facilities confirmed.

K. Check on emergency generators and secure additional generators if needed.

Logistics

A. Arrange for additional petty cash and cash advances (if necessary).

B. Arrange with telephone company additional lines if necessary.

C. Ensure all computers are backed up and secured.

D. Ensure all paperwork/documents are filed and secured properly.

E. Provide control room with customer list, addresses, phone numbers and account numbers.

F. Work with HR department and personnel from other divisions to provide assistance to employees and their families. Assistance may include work to prevent further damage to homes, care for children; work with contractors or insurance companies and provide food/lodging/clothing, etc.

G. Make definite arrangements for contract crew lodging.

H. Make definite arrangements for food/water/drinks for all personnel.

I. Purchase food supply for office/warehouse prior to storm (if the severity of the storm warrants this).

J. Make arrangements for an abundant supply of ice.

K. Make definite arrangements for building security.

L. Make definite arrangements for Division Office supplies (See Annual Preparations, Logistics Manager, and Item E.)

Engineering Manager

A. Provide distribution maps, procedures, etc. as necessary.

B. Ensure SCADA and Mapping System is backed up and operating.

C. Begin constant monitoring customer outages and SCADA system.

C. Ensure SCADA system repeaters have auxiliary power source and/or generator.

D. Monitor time/material needs of contractors.

E. Assemble for safety briefing.

General Manager, Northwest Florida

A. Be located at the Northwest Florida office and constantly monitor the situation and restoration process.

B. Keep media sources informed.

C. Begin activating additional services that will be needed during the restoration process.

Engineering Manager

A. Be located at the Northwest Florida office and constantly monitor the situation and restoration process.

B. Coordinate overall restoration process.

C. Process customer outage system analysis and monitoring SCADA system to determine outage locations.

D. Activate control room.

Logistics

A. Be located at the Northwest Florida office and coordinate the answering and processing of telephone calls.

B. Coordinate assistance to employees and their families.

C. Have food and drinks available to all employees.

D. Work with General Manager and Operations Manager and begin making final logistical arrangements for outside crews.

Line and Service Supervisors

A. Be located at the Northwest Florida office

B. Work with General Manager and Engineering Manager to determine restoration requirements.

9. After the Emergency

General Manager, Northwest Florida

A. Determine manpower requirement from information provided by Others. Contact WPB concerning the situation, if possible, and advise whether or not the additional personnel should continue to the Northwest Florida.

B. Begin making request for additional manpower to contractors.

C. Keep the media informed until such time that the Manager of Communications is on site. At that time, the Manager of Communications will work with the General Manager to keep the Media informed.

Engineering Manager

A. Initiate damage assessment teams.

B. Prioritize and schedule the restoration process.

C. Make assignments and dispatch crews as necessary in order to ensure orderly and efficient restoration.

D. Provide damage assessment to General Manager.

E. Provide updates to General Manager as needed concerning restoration progress.

F. Monitor manpower and equipment requirements and update General Manager as required.

G. Keep a list of all company and outside crews and their locations.

H. Monitor storeroom and remote storeroom for proper operation and inventory. Analyze manpower requirements.

Logistics

A. Provide assistance and serve as liaison to employees and their families.

B. Make final and definite arrangements for lodging, fuel, meals, snacks, coffee, drinks, etc. for all employees and contract employees.

C. Check-in all outside crews and log the personnel and equipment included. Provide assistance with lodging, meals, etc. and keep up with crew locations.

D. Provide assistance as needed.

E. Ensure building security firm is operating at office.

F. Ensure Division office supplies are in place if needed.

G Ensure caters are available as needed.

Line and Service Supervisors

A. Determine and assign appropriate manpower and equipment for each outage situation.

B. Work with General Manager and Operations Manager to determine restoration requirements.

C. Provide outside crews with all necessary information and SAFETY INFORMATION.

F. Ensure all documents are completed prior to material leaving the storeroom and storeroom yard.

G. Monitor and provide assistance in repairing vehicles.

10. Operating Procedure

These instructions are intended to give the employee working on the line information as to the general procedure to be followed under hurricane conditions.

The Line and Service Supervisors will review these instructions with their employees each year so that they may become familiar with the details. This should be done before July 1, each year.

A. Before the Storm

All operating personnel should be instructed as to:

1) Safety and operating procedures to be followed during the storm.
2) Where and when materials and supplies will be available.
3) Their assigned areas and supervisor.
4) Any provisions made for feeding and lodging.
5) Work days will normally be two shifts. Each shift will consist of at least 12 hours but could be 16 hours.
6) The necessity of dividing line crews for clearing and minor repairs.
7) Radio and telephone communication procedures with appropriate list of call letters and telephone numbers.

B. During the Storm

1) First Stage - Repairing All Cases Reported

In order to reduce the over-all outage time to customers who may be interrupted at the beginning of the storm, trouble will be handled in a normal manner during the early stages.

2) Second Stage - Clearing Trouble From the Lines

When the volume of trouble increases to the point where large areas are interrupted, the Line and Service Supervisors will instruct crews to clear trouble from the lines without making repairs in order to maintain service to essential customers and feeders.

a. Secondary or service wires may be cleared by cutting the conductor away from energized lines or by opening the transformer cut-out.

b. Damaged primary conductors may be cleared by cutting and rolling back a primary jumper or conductor at the crossarm or by sectionalizing switching if applicable.

3) Third Stage - De-energizing Main Lines

When the winds reach the point where it is no longer safe for crews to continue clearing operations all restoration activities will cease. The Line and Service Supervisors may instruct crews to de-energize main line feeders at substations if necessary to clear extremely hazardous conditions.

C. After the Storm

Discuss with Safety Coordinator on safety concerns/near miss during restorations.

1) Sequence of Restoration

The sequence of restoration after the winds subside to a safe working level will be as follows:

a. Substations
b. Essential customers
c. Feeders
d. Undamaged primaries (fuse replacement only)
e. Damaged primaries
f. Secondaries
g. Services
h. Street lights

2) Line Patrols

All distribution lines which have "locked out" due to storm to prevent further damage must not be re- energized until patrolled and cleared of primary faults.

11. Telephone Operators Guide

During any major interruption our customers will naturally be concerned about falling wires, burning wires, defrosting refrigeration and even their daily routines in which electricity plays a part. The most important test we have is maintaining good relations during these emergencies. Those employees answering telephones must keep this in mind - be calm, pleasant and sympathetic with the customer and at the same time getting the necessary information needed to clear dangerous conditions and restore service as soon as possible, giving as much information to the customer that is available.

Outlined below is a suggested procedure to be used during three different phases of an interruption (The General Manager or Engineering Manager will determine when Phase 1 begins and when movement to Phase 2 and 3 is indicated):

Phase 1 - will be in effect until the time of the first trouble call until it is evident that there is widespread damage in the area.

Phase 2 - will be in effect following Phase 1 until damage evaluations have been made and estimate of the time required to make major repairs.

Phase 3 - will begin in an area where an estimate of the time required to make major repairs is available and will continue until all trouble is clear.

Your supervisor will advise you when conditions change from one phase to another in accordance with the routines outlined below:

Suggested Answering Routine to be used by All Operators

Phase 1 - Early Trouble Prior to Extensive Damage

1. "Florida Public Utilities, May we help you please."

   a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"
   b. If wire down, pole broken, tree on a line, ask:
      1) "Is the wire burning?"

2) "Are your lights working?"
3) "We hope to be able to make repairs shortly. Thank you very much for calling."

Phase 2 - Extensive Damage Evident But Estimate of Repair Time Not Available

1. "Florida Public Utilities, May we help you please."

   a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"
   b. If wire down, pole broken, tree on a line, ask:
      1) "Is the wire burning?"
      2) "Are your lights working?"
      3) "Our electric system has suffered considerable damage in your area and we haven't been able to make an estimate of the time required for repairs. Our crews are working now and if your service has not been restored by (morning/afternoon) please call again. Thank you."

Phase 3 - Damage Evaluated and Repair Time Estimated

1. "Florida Public Utilities, May we help you please."

   a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"

   b. If wire down, pole broken, tree on a line, ask:

      1) "Is the wire burning?"
      2) "Are your lights working?"
      3) "We have crews working on the lines which serve your area and repairs should be made by (time). If your electricity us not on by that time, please call again. Thank you."

Operators Guide

You will be relieved for meals, etc., and at the end of your shift.

Remember a properly handled telephone conversation with a customer can create an immeasurable amount of good will. When conversing with customers, keep the following points in mind:

1. Be courteous to each customer.
2. Give him as much information as is available of the restoration work.
3. Record each call and report the information vital to restoring the customer's service.
4. Handle each call as briefly as possible.
5. Thank the customer for calling.
6. Do not give the news media information. If a request for new information is received, record the name of the individual, news organization, telephone number and specific request. Inform the caller that a company representative will return the call. The information should be sent immediately to the General Manager, Northwest Florida.
7. During an emergency condition, some customers will contact the company for reasons that do not pertain to the emergency. These calls should be recorded and the exact customer needs should be stated in the remarks column. These calls may include disconnections, reconnections, etc., or may be a personal call to an employee. After the contact has been recorded, the completed form should be given directly to the supervisor.

Entering Outages

Each customer call will be recorded in the Outage Management System. The information entered should be entered accurately to ensure the system operates properly. The information entered will be stored as a permanent record and will be used to analyze the nature of the outages.

Should emergency situations come to your attention, please notify a supervisor. The method of this documentation will be determined.

12. Media/Public Information Guide

In order to monitor all information given to media and public sources, only the General Manager, Northwest Florida, Manager of Communications or their designee will make press releases. If other employees are asked by media or public agencies for information, politely ask them for contact information so the General Manager, Northwest Florida or Manager of Communications can provide them the latest information.

13. Warehouse Procedure

During an emergency, material is vital to promptly and efficiently restore service to all customers. It is therefore important to monitor all stock levels to ensure adequate supplies are on-hand and if stock levels get low, be able to quickly order additional materials.

All material taken from the storeroom or remote storeroom will have the appropriate documentation completed before being removed from the stores area. The stores personnel will ensure this is followed.

Only authorized personnel should be in the stores area. Stores personnel will monitor those in the stores area to ensure compliance.

14. Lockbox Procedure

The section will involve that information and other procedures necessary to ensure that the Lockbox operation continues to operate during any emergency that may occur.

Annual

1. The Customer Care Manager will update information regarding the Lockbox operations.
2. The Lead Customer Service Representative will update information regarding the locations of Bank of America locations should it be necessary to take deposits to other banks if the courier service is not available. This may also be necessary should courier service be disrupted due to other reasons.
3. The General Manager, Northwest Florida will initiate conference call with the President, Controller, IT Director, Customer Relations Director, Customer Care Manager and others as needed to discuss alternatives should a disaster disrupt operations in NW Florida.
4. Information on contingency locations will be updated by the Customer Care Manager.

Prior to the Emergency

1. The Logistics Manager will contact the post office to determine mail delivery schedules and alternatives. Rerouting of mail may be required and involve the Customer Relations Director notification of billing contractor.
2. The General Manager, Northwest Florida will initiate conference call with the President, Controller, IT Director, Customer Relations Director, NW Florida Logistics Manager and others as needed to setup alternative plans for processing payments.
3. The group will decide on the appropriate contingency plan necessary based on the emergency situation and begin contingency operations.

4. The Logistics Manager will ensure that protective covering is available and installed on all Lockbox equipment and server to ensure damage, if any, is minimized.

After the Emergency

Contingency Plan #1

1. Mail will be delivered to the Marianna Post Office and personnel will be used immediately to continue to process payments. These personnel will not participate in restoration activities but will be solely responsible for Lockbox operations. If required additional personnel will be added to current staffing.
2. If courier service is not available beginning on the first day of processing, personnel will be sent to BOA locations capable of processing encoded checks to make deposits. The deposits will be sent on the morning following the days work. Preferably, the deposit will be delivered to the BOA location at 2262 North Monroe St. in Tallahassee. This and other locations will be verified on an annual basis.
3. Information concerning daily processing will be updated on a daily basis. This may be accomplished as normally handled, by sending the information via internet from a remote location or by mailing a CD overnight mail to the IT director to be input from WPB.

Contingency Plan #2

1. Due to the damage to the NW FL facilities, processing is not available. Mail will be picked up at the Marianna Post office and forwarded to Central Florida for processing. The mail may be delivered by local personnel to Lake City where Central Florida personnel will pick up the mail. The personnel form the two divisions will meet at Exit #82 on Interstate 75 (Interstate 75 and Highway 90) and exchange the mail.
2. If mail can be forwarded in an efficient manner prior to the emergency, all payments will go directly to the Central Florida office. This may not be a good alternative due to the issues with the USPS.
3. Central Florida personnel will process the mail manually using personnel as needed. Deposits will be made normally on a daily basis.
4. As soon as NW FL is capable of processing payments normally, payment processing will be handled normally.

Contingency Plan #3

1. Due to the inability of the Corporate Office to accept updated information from the Lockbox, it will be necessary to send payment information to a remote location.
2. NW FL will continue to process payments normally and make deposits accordingly.
3. The IT Director will provide NW FL with the appropriate directions on where to send the information concerning payments. This information will be added to this procedure when it becomes available.
4. All information on payments will be saved to a CD on a daily basis and stored in a safe place. If possible a hard copy of the information should also be printed and stored in a safe place.

15. Personnel Backup Contingencies

Should the following personnel not be available during the emergencies, personnel in the positions listed below that position will fill in as needed.

General Manager, Northwest Florida
Engineering Manager
Service Supervisor
Line Supervisor

Engineering Manager
Service Supervisor
Line Supervisor

Logistics Manager
Energy Conservation Representative

16. **Employee Assignments**

TENTATIVE SCHEDULE

DAY SHIFT
6:00 AM Reporting Time

OFFICE	
Lynwood Tanner	General Manager, NW
Steve Toole	Engineering Manager
Janine Roye	Logistics Lead
Mason Brock	Logistics
Shane Magnus	Engineering
Sally Jones	Customer Care Supervisor
Kim Hall	Telephone
Laura McCoy	Telephone
SERVICE / LINE CREWS	
Jerry Lewis	Line Supervisor
Darryl Grooms	Crew Leader
Woody Hall	Senior Lineman
James Ussery	Senior Lineman
Alvin Foran	Senior Lineman
Kevin Harris	Lineman
Jeremy Hill	Lineman
Andy Bevis	Lineman
Chris Allen	Apprentice Lineman
Bobby See	IMC Technician I
John Griffin	IMC Technician I
STORES	
Donna Fowler	Stores Supervisor
Doug Jones	Warehouseman
PATROL/GUIDE/SAFETY	
Rhondon Gray	SAFETY
Virginia Nail	Patrol/Guide
Kate Jones	Patrol/Guide

NIGHT SHIFT
6:00 PM Reporting Time

OFFICE	
Donna Fowler	Stores Supervisor
Pam Thomas	Telephone
Sue Pitas	Telephone
Stephen Amos	Telephone
Donnie Tew	Engineering /Cust. Outages
SERVICE CREWS	
Brady Foran	Crew Leader
Stephen Amos	Apprentice Lineman
PATROLMAN/GUIDE	
Claude Holden	Patrol/Guide

17. Emergency Assistance List

Company	Contact	Telephone	Available Resources
Gulf Power Company	Andy McQuagge	(850) 872-3220	Crews
West Florida Electric Coop	Bill Rimes	(850) 263-6518	Crews
FPU-Fernandina Beach	Bill Grant	(904) 277-1957	Crews
Davey Tree	Russell Brooks	(352) 279-8622	Tree Crews
DaveyTree	Russell Brooks	(228) 396-5810	Tree Crews
City of Tallahassee		(850) 599-5811	Crews
Talquin Electric Coop		(850) 627-7651	Crews
Gulf Coast Electric Coop		(850) 877-6166	Crews
Public Service Commission	Joseph Jenkins	(850) 488-8501	
Public Service Commission	Bob Trapp	(850) 488-8501	
Red Simpson Inc	John Simpson	(318) 487-1074	Crews
Florida Electric Power Coord Group	R J Midulla	(813) 289-5644	Crews
Mastec	Copper Nelson	(850) 519-0664	Crews
Utilicon	Gene Holley	(478) 348-3233	Crews
		(850) 890-0131 cell	
		(850) 638-7129 hom	
Harper Electric	Mark Harper	(334) 222-7022	
		(334) 222-7854	
		(334) 343-1703 cell	

Vehicle Repairs Assistance

Company	Contact	Telephone	Available Resources
Altec Industries Inc		(205) 458-3850	Mechanical Repairs
Altec Industries Inc		(205) 458-3857	Mechanical Repairs
Altec Industries Inc		(205) 458-3889	Mechanical Repairs
Altec Industries Inc		(205) 458-3849	Mechanical Repairs
Altec Industries Inc		(205) 458-3848	Mechanical Repairs
Auto Clinic	Office	(904) 482-6632	Mechanical Repairs
Auto Clinic	Mike Krieser	(850) 569-8475	Mechanical Repairs
Auto Clinic		258-6274	Mechanical Repairs
Dale Brannon	Dale Brannon	352-4613 shop	Wrecker
		(850) 573-0275 cell	Wrecker

18. Emergency Stock Requirements

Bin #	Description	Quantity Required	Quantity On Hand
31-1320	Wire, #4 AAAC Bare	25,000	
31-1550	Wire, #4 AL Triplex	10,000	
31-1590	Wire, #1/0 AL Triplex	10,000	
31-1650	Wire, #2 AL Quad	1,000	
31-1670	Wire, #1/0 AL Quad	1,000	
31-1690	Wire, #4/0 AL Quad	1,000	
31-1720	Wire, 3/8 Guy	3,000	
35-1160	Arrester, MOV, Line	75	
35-1165	Arrester, MOV, Riser	25	
35-2710	Cut-out, Fused, 100A	48	
35-2720	Cut-out, Load Break, 200 A	24	
35-2860	Guy Grip, 3/8 Galv	100	
35-2975	Insulator, Pin Type, 7500 V	100	
35-3030	Insulator, Horizontal, 35 V	25	
35-3110	Insulator, Suspension	100	
35-3115	Insulator, Fiberglass Rod 12"	50	
35-3120	Insulator, Fiberglass Rod 5'	25	
35-3470	Pin, Fiberglass Stand Off	100	
35-3520	Pole, 30'/6	30	
35-3550	Pole, 40'/4	30	
35-3575	Pole, 45'/3	25	
35-4039	Ties, #4 Side	50	
35-4060	Ties, #477 Side	50	
35-4068	Ties, #4 Wrap lock	100	
35-4100	Ties, #477 Wrap lock	50	
37-1005	Clamp, Dead-end #6-#2 Service	200	
37-1020	Clamp, Dead-end #1/0 Service	100	
37-1390	Connector, H Type, WR-159	1,000	
37-1400	Connector, H Type, WR-189	1,000	
37-1405	Connector, H Type, WR-289	200	
37-1410	Connector, H Type, WR-279	100	
37-1420	Connector, H Type, WR-379	100	
37-1430	Connector, H Type, WR-419	100	
37-1440	Connector, H Type, WR-399	150	
37-1456	Connector, H Type, WR-885	100	
37-1460	Connector, H Type, WR-835	100	
37-1620	Connector, Vise Action, #6 Cu	100	
37-1630	Connector, Vise Action, #4 Cu	100	
37-1650	Connector, Vise Action, #2 Cu	100	
37-2192	Sleeves, Auto Splice, #4 AL	500	
37-2200	Sleeves, Auto Splice, #1/0 AL	50	
37-2208	Sleeves, Auto Splice, #3/0 AL	25	
37-2210	Sleeves, Auto Splice, #4/0 AL	25	
37-2218	Sleeves, Auto Splice, 336 AL	100	
37-2225	Sleeves, Auto Splice, 477 AL	150	

Bin #	Description	Quantity Required	Quantity On Hand
37-2550	Sleeves, Triplex Neutral, #4 AL	100	
37-2560	Sleeves, Triplex Neutral, #2 AL	75	
37-2610	Splice, Guy	50	
37-2740	Stirrup, #4	100	
39-1170	Fuse Link, 2 ½ Amp	150	
39-1190	Fuse Link, 4 Amp	100	
39-1220	Fuse Link, 7 Amp	50	
39-1230	Fuse Link, 10 Amp	150	
39-1240	Fuse Link, 15 Amp	100	
39-1250	Fuse Link, 20 Amp	25	
39-1260	Fuse Link, 25 Amp	25	
39-1270	Fuse Link, 30 Amp	25	
39-1280	Fuse Link, 40 Amp	25	
39-1290	Fuse Link, 50 Amp	25	
39-1300	Fuse Link, 60 Amp	25	
91-1090	Transformer, 15 KVA	20	
91-1100	Transformer, 25 KVA	15	
91-1110	Transformer, 37.5 KVA	5	
91-1120	Transformer, 50 KVA	5	

19. <u>Transportation and Equipment</u>

TRUCK #	ITEM DESCRIPTION	X	Y	Z	GPS INSTALLED	VEHICLE OPERABLE	DATE	BY	CONTACT/ COMMENTS
810	Fork Lift								
859	Pole Trailer								
860	Material Trailer								
861	Combination Pole Trailer								
862	Wire Retrieving Trailer								
863	Wire Pulling Trailer								
969	Freightliner/Derrick								
979	Freightliner/Derrick								
968	Material Handler/Freightliner								
980	Bucket Truck								
977	GMC Pick-Up Truck (Magnus)								
982	Pick-Up Truck (Griffin)								
991	Rav4(Jones)								
990	Rav4 (Nail)								
957	Toyota Pre-Runner (Tew)								
954	Altec Material Handler								
974	Altec Material Handler								
956	Chevy Pickup (Flag)								

959	Toyota Tundra (Spare)								
985	Ford Pickup (Tanner)								
983	Altec Service Material Handler								
962	GMC Savanna Van (See)								
965	Altec Material Handler								
986	Ford Pickup (Lewis)								
989	Toy. Pickup (Holden)								
865	Signboard								
866	Trailer								
978	GMC Pickup (Toole)								
987	Ford Exp. (Shelley)								
984	Toyota Rav4 (Brock)								
992	Chevy Pickup (Gray)								

Note: X = Operational
Y =
Material Z
= Fuel

20. Critical Customer List

A. Hospitals, Clinics, Nursing Homes

Name	Address	Telephone	Contact Person
Jackson Hospital	800 Hospital Dr.	526-2200	Larry Meese
Marianna Convalescent Ctr.	805 5th Ave.	482-8091	Johnnie Cloud
The Nursing Pavilion	710 3rd Ave.	526-3191	Greg Mitchell

B. Public Utilities

Name Person	Address	Telephone	Contact
Marianna Waste Water	2832 Davey St.	482-4353	Jim Dean
Sunland Waster Water T.P.	3693 Industrial Park	"	"
Park St. Pump Station	2988 Park St.	"	"
Davis Field Pump Station	4457 South St.	"	"
Sheffield Pump Station	3325 Old US Rd.	"	"
Marianna Well #5	Clinton & Noland St.	"	"
Marianna Well #6	Ninth Av. & Third St.	"	"
Marianna Well #1	Hwy 90 W/ Pool	"	"
Marianna Public Work	4168 South St.	"	"
Marianna Gas Department		"	"

C. Major Disaster Shelters/Motels

Name	Address	Telephone	Contact Person
Best Western 2086 Hwy 71	526-5666		
Comfort Inn	2175 Hwy 71	526-5600	
Exective Inn	4113 Lafayette	526-3710	
Best-Value Inn 4168 Lafayette	482-4973		
Chipola Jr. College	3094 College Dr.	526-2761	
Cottondale High School	2680 Levy St	482-9821	Steve Benton
Malone High School	5361 North St	482-9950	Steve Benton
Marianna High School	Caverns RD.	482-9605	Steve Benton
Marianna Middle School	4144 South St.	482-9609	Steve Benton
Riverside Elementary	2958 Cherokee St.	482-9611	Steve Benton
Golson Elementary	4258 Second Av.	482-9607	Steve Benton
Microtel	4959 Whitetail Dr.	526-5005	Harkins
Hampton Inn	2185 Hwy 71	526-1006	D Thompson
Budget Inn	4135 Lafayette St	482-2700	R Shah
Fairfield Inn	4966 Whitetail Dr.	482-2578	
Ramada Limited	4655 E. Hwy 90	526-3251	
Comfort Inn	2214 Hwy 71	482-7112	
Marianna Inn	2222 Hwy 71	526-2900	

D. Municipal and State Emergency Services

Name	Address	Telephone	Contact Person
Florida Highway Patrol	3613 Hwy 90	482-9512	Lt. Moore
Jackson Co. Sheriff Dept.	4012 Lafayette St	482-9624	L. Roberts
Cottondale Police Dept.	2659 Front St.	352-4361	Watford
Marianna Police Dept.	2890 Green St.	526-3125	H. Bagett
Jackson Co. Fire & Rescue	Industrial Park Dr.	482-9669	R Brown
Alford Fire Dept.	1768 Georgia St	638-8657	B Yongue
Cottondale Fire Dept.	2669 Front St.	911	
Malone Fire Dept.	5187 Ninth Ave.	911	M Padget
Marianna Fire Dept.	4425 Clinton St.	482-2414	N. Lovett
Emergency Management	.	482-9683	Andreason
Emergency Management	.	573-1058	Andreason

E. Communication and Broadcasting Services

Name	Address	Telephone	Contact Person
WTOT/WJAQ Radio	4376 Lafayette St	482-3046	D Moore
Jackson County Floridan	4403 Constitution Ln	526-3614	V. Roberts
WMBB	Panama City	850-769-2313	M. McAfee

F. Major Food Storage/Processing Facilities

Name	Address	Telephone	Contact Person
Malone IGA	5417 10th St.	569-2635	
Grocery Outlet	Lafayette St.	526-5528	D. Pendergrass
Sunshine Food-Greenwood	S. Main	594-1286	
Winn Dixie	4478 Lafayette St	482-5303	Russ
Daffin Food Service	2867 Estes	482-4026	J. Milton
Walmart Superstore	Highway 71	526-5744	M. Gilmore
Save-a-lot	4700 Hwy 90	526-4700	

G. Correction Facilities

Name	Address	Telephone	Contact Person
Arthur G. Dozier School	4111 South St	482-9700	R. McKay
Marianna Work Camp		482-9561	
Federal Correctional (FCI)	3625 FCI Rd	526-2313	L. Gross

H. Airports

Name	Address	Telephone	Contact Person
Chipola Aviation Inc.	3633 Industrial Park Dr	482-8480	H. Foran
Panhandle Aviation	Greenwood	594-3224	
Marianna Airport/ Ind. Park	Industrial Park Dr.	482-2281	

***EMERGENCY FUEL**

24HRS. DONALD CUTCHINS
(h)352-2906 ©573-1505

STORM/FUEL SHORTAGE
(w) 482-7003 © 643-8925

21. Address and Telephone Listing of Active Employees

Name	Address	Telephone
Allen, Chris	3601 Guinea Runway, Marianna , Fl. 32448	693-4301
Amos, Stephen	2982 Dixon, Marianna, Fl. 32446	557-0800
Bevis, Andy	3400 Riley Drive, Marianna, Fl 32448	557-6484
Brock, Mason	2970 Chase Way, Marianna, FL 32446	557-0180
Foran, Alvin	16846 NW CR 379A, Bristol, FL 32321	643-2582
Foran, Brady	2948 Gardenview Rd Cottondale, FL 32431	579-4238
Fowler, Donna	PO Box 1250, Marianna, Fl. 32446	557-3495
Gray, Rhondon	PO Box 31 Cottondale, FL 32431	557-6490
Griffin, John	2776 Kynesville Road, Cottondale, FL 32431	579-2479
Grooms, Darryl	3568 Flat Rd Greenwood, FL 32443	209-7144
Hall, Kim	3791 Old Cottondale Rd, Marianna, FL 32448	526-3144
Hall, Woody	3791 Old Cottondale Rd, Marianna, FL 32448	526-3144
Hill, Jeremy	3158 Swaills Rd, Alford, FL 32420	326-0266
Harris, Kevin	2341 Cycle Lane, Cottondale, FL 32431	579-0101
Holden, Claude	2126 Tanner Rd Marianna, FL 32448	526-2664
Jones, Doug	PO Box 654, Malone, Fl. 32445	569-2836
Jones, Kate	25404 NW Bowden Rd., Altha, Fl. 32421	762-2984
Jones, Sally	22473 NW Goodwin Rd., Altha, Fl 32421	762-8366
Lewis, Jerry	15869 NW Pea Ridge Road, Bristol, FL 32321	643-5797
Magnus,Shane	16405 Castile Ave.,Panama City Beach 32413	209-3493
McCoy, Laura	2694 Old Airbase Road, Marianna, FL 32448	526-2998
Nail, Virginia	5701 Nubbin Ridge Rd., Greenwood, Fl. 32443	594-7570
Pitas, Carolyn (Sue)	3270 NW Stone Ave, Altha FL 32421	762-9540
Roye, Janine	2850 Paulding Court, Alford, Fl. 32420	579-4754
See, Bobby	2679 Dock Rd, Cottondale, FL 32431	579-4467
Shelley, Buddy	3849 Hwy 90, Marianna, Fl. 32446	557-6480
Tanner, Lynwood	P. O. Box 6401, Marianna, FL 32447	579-4679
Tew, Donnie	4951 Carousel Loop, Marianna, FL 32448	482-4126
Thomas, Pamela	3350 Plantation Circle, Marianna, FL 32446	482-2847
Toole, Steve	915 Daniel Dr., Alford, Fl. 32420	579-4455
Ussery, James	2510 Railroad St., Cottondale, FL 32431	352-3928

22. Emergency Telephone List

A.	Telephone Repair	
	Century Link (Wilton Crawford)	526-3481 or (611)
B.	Radio Repair	
	Verizon (Jerry Fox)	(850) 867-9633
C.	Gulf Power Company	
	Pensacola Dispatcher	444-6517
	Panama City Dispatcher	872-3261
	Storm Coordinator	785-8305
	Mike Menk (Southern Company)	(205)257-2599 / (205)515-2066 mobile
	Andy McQuagge	872-3220
D.	Emergency Management	
	Jackson County (Rodney Andreason)	482-9633
	" " "	536-4500
	Calhoun County (Don O'Bryan)	674-8075/5161
	Liberty County (Jerry Butler)	643-3477
	State Office (Eric Torbett)	413-9911
E.	Law Enforcement - 911	
	Jackson County	482-9624 / 482-9648
	Calhoun County	674-5049/4275
	Liberty County	643-2235
	Marianna	526-3125
	Greenwood	482-9648
	Malone	482-9648
	Cottondale	352-4361
	Alford	482-9648
	Altha	762-3900
	Bristol	643-2235
	Blountstown	674-5987
	Bascom	482-9648
	Florida Highway Patrol	482-9512
F.	Ambulance - 911	
	Jackson County	482-9669 / 482-9668
	Calhoun County	674-5411
	Liberty County	643-2235
G.	News Media	
	WTOT/WJAQ (Don Moore)	482-3046
	Jackson County Floridan	526-3614
	WTVY-Channel 4 TV/Dothan	(334)792-3195
	WJHG-Channel 7 TV/Panama City	234-2125 / 526-5727
	WMBB-Channel 13 TV/Panama City	763-6000 / 482-8007

H. City/County Officials

Jackson County	482-9633
Calhoun County	674-4545
Liberty County	643-5404
Alford	579-4684
Bascom	569-2234
Cottondale	352-4361
Greenwood	594-1216
Malone	569-2308
Marianna	482-4353
Altha	762-3280
Bristol	643-2261
Blountstown	674-5488

I. Public Service Commission

Tim Devlin, Dir. Economic Regulation	413-6900
Dan Hoppe, Dir, Auditing and Safety	413-6480
Joseph Jenkins	413-6626
Bob Trapp	413-6632
Roland Floyd	413-6676
Connie Kummer	413-6701

23. Logistics

Motels:

Best Western	526-5666
Comfort Inn	526-5600
Microtel	526-5005
Executive Inn	526-3710
Hampton Inn	526-1006
Holiday Inn Express	526-2900
Ramada Limited	526-3251
Best Value Inn	482-4973

Air Mattress/Cots:

Loftin's Rental Center	526-4680
North Florida Rentals	526-7368

Laundry & Linen Services/Supplies:

UniMac Express Laundry	482-6504
Nifty Cleaners	482-2825

First Aid Supplies:

Waco Drugs	482-5781	Kelson Drugs	526-2839
Paramore's	482-3924	Watson's	482-4035
CVS			

Restaurants:

Captain D's	482-6230
Beef O Bradys	482-0002
Fortune Cookie	526-3735
Jim's Buffet & Grill	526-2366
Madison's Warehouse	526-4000
Dairy Queen	482-1055
Sonny's Barbecue	526-7274
Ruby Tuesday	526-7100
Waffle Iron	526-5055
Zaxby's	633-4545
The Oaks	526-1114
Hungry Howies	526-7878
Ruby Tuesday	526-7100
Waffle Iron	526-5055
Zaxby's	633-4545
The Oaks	526-1114
Hungry Howies	526-7878
Firehouse Subs	482-5883
San Marcos	482-0062
Pizza Hut	482-5900
Gazebo Rest.	526-1276

Catering:

Sweet Stuff Bakery	526-2250

Food Stores:

Daffin Food Service	482-4026
Grocery Outlet	526-5528
Walmart Superstore	526-5744
Malone IGA	569-2635
Winn Dixie	482-5303

Cellular Phones:

Verizon	526-7701

Water Supply:
FPU (Co. generator to supply water)
Nantze Springs Water Co. 800-239-7873

Ice Supply:

Winn Dixie	482-5303

Service Stations:

Big Little Store	526-5743
Cottondale Texaco	352-2804
Marianna Texaco	482-6105
Hartsfield Mini-Mart	482-4545
K & M Expressway	526-5575
McCoy's Chevron	526-2921
Marianna Chevron	526-2183
Marianna Truck Stop	526-3303
Mike's Texaco, Malone	569-2401
Nugget Oil	482-8585
Sangaree BP	482-5241
Murphy USA	482-6149
Stoney's	482-2028
Tom Thumb	482-4842

Vehicle Repair Facilities:

Baker Equipment	800-765-4908
Altec Industries Inc	205-323-8751
Thompson Tractor Co	526-2241
Beall Tire Co	482-323
Auto Clinic	482-6632

Flashlights (20 w/batteries):
Quantity on hand
Mayer Electric (Additional)800-216-6712

Portable AM/FM Radios w/batteries:

WalMart	526-5744

Necessary Supplies for Northwest Florida Office:

Food Items:

Item	Quantity	Item	Quantity
Bread	15 loafs	Peanut Butter	5 jars
Gallon Size Water	50 Gallons	Bottle Size Water	100 bottles
Jelly (Grape & Strawberry)	5 jars	Milk	5 gallons
Orange Juice	3 gallons	Soft drinks (Miscellaneous)	20 two liter bottles
Soft drinks (miscellaneous)	10 cases	Margarine	6 each
Cookies (miscellaneous)	10 packs	Crackers	10 boxes
American Cheese	3 packs	Cheddar Cheese	5 blocks
Lunch Meat (miscellaneous)	10 pounds	Potato Chips (miscellaneous)	6 bags
Pretzels	4 bags	Tomatoes	1 bag
Onions	1 bag	Mayonnaise	4 each
Mustard	3 each	Ketchup	3 each
Pastries (miscellaneous)	5 boxes	Bagels	2 packs

Supplies:

Item	Quantity	Item	Quantity
Paper Plates	10 packs	Paper Bowls	5 packs
Plastic Utensils	5 packs	Aluminum Foil	10 boxes
Garbage Bags	5 boxes	Foil Pans/Trays	15 each
Paper Towels	20 rolls	Dish Towels and Rags	10 each
Serving Utensils	10 each	Dish Soap	3 each

24. Service Plan to Supply Power to FPU Offices

During an emergency it is imperative that power be restored to the office/complex located at 2825 Pennsylvania Av. as soon as possible. Also of the utmost importance is to ensure the feeder to the building is maintained in optimum working order at all times. This includes tree trimming, replacing deteriorated poles, replacing defective equipment, etc.

After an emergency in which power is lost to the office/warehouse, someone will immediately go to the Marianna Substation in order to determine the status of the breaker #9854 (South St Feeder). That feeder will also be patrolled to determine what will be needed to restore service to the office/warehouse. All available personnel will be utilized to restore power.

If required, downstream switches should be opened so that power may be restored to the warehouse as soon as possible.

25. Damage Assessment Plan

After a major storm or emergency occurs it will be necessary to access the damage to the system as quickly and accurately as possible. The following shows the assignments for a quick visual system inspection which is to be performed as soon after the storm/emergency as possible.

General Manager, Northwest Florida
Check Hospital feeder from the hospital to Marianna Substation. Check Marianna Substation.

Safety Coordinator
Check Chipola Substation. Check along Old US Rd to Hwy 90.

Service Supervisor
Check along Kelson Av to Penn Av then down Penn Av to the office.

Line Supervisor
Check Caverns Rd Substation. Check along Hwy 71 South to Hwy 90 then south on West Caledonia to South St then west on South St to Penn Av then north on Penn Av. to the warehouse.

Engineering Manager
Check along Hwy 90 from Marianna Substation to Penn Ave.

26. Damage Assessment Form

The Damage Assessment Form to be completed and returned as soon as possible after the storm/emergency. To ensure proper planning it is essential that this form be completed neatly, accurately and completely.

FLORIDA PUBLIC UTILITIES

FLORIDA PUBLIC UTILITIES COMPANY

NORTHEAST FLORIDA DIVISION

2014
EMERGENCY PROCEDURES

1. OBJECTIVE

The primary objective of the procedure is to provide guidelines under which the Northeast Florida Division of Florida Public Utilities Company will operate in emergency conditions. The following objectives will ensure orderly and efficient service restoration.

A. The safety of employees, contractors and the general public will have the highest priority.

B. Early damage assessment is required in order to develop manpower requirements.

C. Request additional manpower as soon as conditions and information indicate the need.

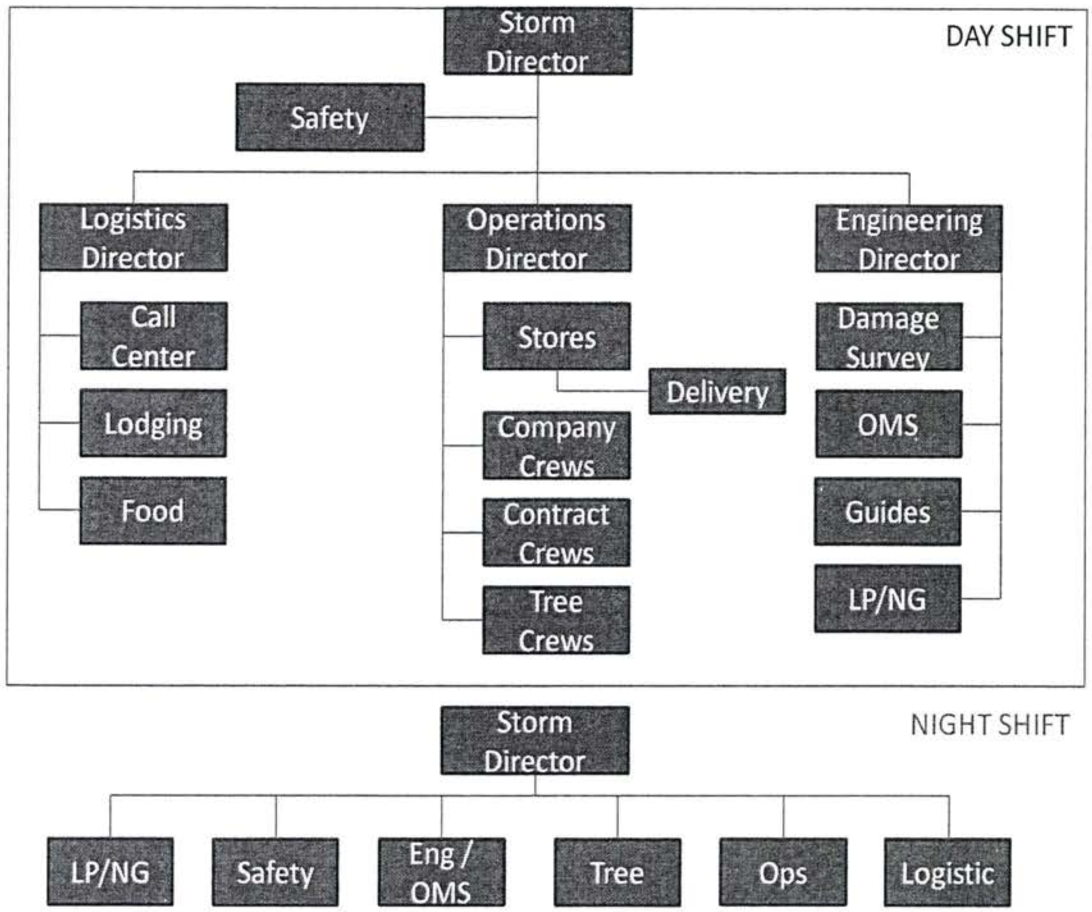
D. Provide for orderly restoration activities in order to provide efficient and rapid restoration.

E. Provide all logistical needs for employees and contractors.

F. Provide ongoing preparation of our employees, buildings, equipment and support function in advance of an emergency.

G. Provide support and additional resources for employees and their families should they need assistance to address injury or damage as a result of the emergency situation.

2. STORM MODE ORGANIZATIONAL CHART



2014

DAY SHIFT		NIGHT SHIFT
BILL GRANT	STORM DIRECTOR	JORGE PUENTES
CHRIS HEBRT	ENGINEERING DIRECTOR	SHANE MAGNUS
RICH CRIGGER	OPERATIONS DIRECTOR	TBD*
ROGER LACHARITE	LOGISTICS DIRECTOR	PATTI THORNTON
TOM MOEN	SAFETY	TBD*

*WILL BE FILLED FROM AVAILABLE RESOURCES

3. EMERGENCY PERSONNEL POLICY

As a public utility we provide essential services for our customers and the general public. Therefore, the purpose of the Company's Emergency Personnel Policy is to encourage employees to make every reasonable effort to report to work. Each employee performs an essential role in the Company's operation and it's important that you report to duty as scheduled during an emergency. Restoring and maintaining services after a major storm is a difficult job and requires everyone's best efforts. Of necessity, employees may be required to assist other departments or perform functions outside of their normal daily work assignment. It will take every employee's cooperation before, during and after an emergency.

A. If you are on the job when the storm approaches, your supervisor will inform you of your storm assignment. Employees not directly involved in maintaining services may be released to go home before the storm threatens safe travel.

B. If you are off-duty, call your immediate supervisor as soon as possible after an emergency condition is announced. An Emergency Condition Warning is usually given within 24 hours of occurrence. Your supervisor will inform you as to where and when you'll be needed prior to, during, and after the storm. If your supervisor is not available call his/her immediate supervisor or the Northeast Florida Office. This requirement applies to all electric, natural gas and propane division employees when an emergency threatens any of the Company's electric service areas.

C. After the emergency passes, all personnel not on duty during the storm will report as soon as possible to their supervisor or his/her designate by telephone. In the event the telephones are not working or you are unable to communicate with your supervisor or the company office, report in person to your regular work station as soon as possible during daylight hours.

D. EMPLOYEES ARE TO MAKE EVERY REASONABLE EFFORT TO REPORT TOWORK. IT'S UNDERSTOOD THAT THERE WILL BE INSTANCES WHERE EMPLOYEES JUST CAN'T GET TO WORK. EMPLOYEES WHO DO NOT REPORT TO WORK WILL NOT BE PAID. IF YOU ARE UNABLE TO REPORT TO WORK MAKE EVERY EFFORT TO CONTACT YOUR SUPERVISOR TO REPORT YOUR ABSENCE. DISCIPLINARY ACTION UP TO AND INCLUDING DISCHARGE MAY BE TAKEN AGAINST EMPLOYEES WHO DO NOT REPORT TO WORK WITHOUT JUST CAUSE.

E. Personal emergencies are common results of a major hurricane but, unless life threatening, will not be acceptable as an excuse for not reporting to work. Evacuation from a hurricane threatened area to a remote location from which you cannot promptly return to your home is also not acceptable as a reason for not reporting to work.

F. The Company will endeavor to provide assistance and shelter to employees and their immediate families should an employee need or request assistance.

G. Unless emergency conditions warrant, employees will not be required to work in excess of sixteen (16) consecutive hours.

The success of the emergency plan requires the cooperation and efforts of all of our employees. Employees may be required to return from their vacation or Company sponsored travel. Therefore, it will be the responsibility of each supervisor to determine the location of each of their employees on Company sponsored trips to facilitate their recall if conditions warrant their return when the emergency plan is implemented. Employees who are on vacation will notify, by telephone, their supervisors of their location and availability when an emergency threatens to strike our service area. Supervisors will consult with their department head to determine the feasibility and need to recall employees from vacation or Company sponsored trips. All employees are essential for the continued operation of the Company obligations and Company objectives.

The Company will develop information which will assist employees and their families before, during and after the storm. The Electric Operations Manager, Northeast Florida will be responsible for obtaining the information and communicating this information to the employees. The Company will attempt to provide as much assistance as practical to the employees and their families during emergency situations.

However, it is the responsibility of each employee to develop a personal plan that can be quickly implemented in case a storm impacts our area. This plan should involve the protection of family and property which can be put into action quickly and allow for compliance with the above mentioned requirements. Every effort will be made to allow employees time off prior to a storm to make preparations for the event.

4. GENERAL RESTORATION GUIDELINES

These general guidelines are issued to provide overall guidance as to emergency system restoration activities. These guidelines will be followed as much as practical in emergencies caused by hurricanes, tornadoes, ice storms and other natural disasters.

These guidelines are not intended to nor will they put in jeopardy the safety of any employee or their family. Dependent upon the intensity of the storm as determined by the company's management, employees will be required to report to work as instructed. If the intensity of the storm is such that weather conditions will be extremely severe, only a skeleton crew will be present at the work location. All others will report for duty as soon as conditions subside to a reasonable level. Those on vacation will be expected to report for duty.

The Northeast Florida office building was designed to withstand 160 mph sustained winds. Should winds be expected to significantly exceed these ratings, alternative locations will be identified and restoration will be relocated to an appropriate facility.

Restoration activities will be handled in the following manner:

A. During the early stages of the emergency, restoration will be handled in the usual manner. All service will be restored as soon as possible.

B. As the storm intensifies and trouble reaches major proportions, the main restoration activities will be limited to keeping main feeders energized by clearing trouble without making repairs.

C. When the intensity of the storm is such that work can no longer be done safely, all work will cease and personnel will report to the office or other safe location. Ariel work will not be conducted when wind speed reach 40 miles per hour.

D. When the storm has subsided to a reasonable level and it is safe to begin restoration activities damage assessment and restoration of main feeders to critical customers will begin.

E. Restoration activities will continue in an effort to restore service in the following manner:
   1) Substations
   2) Main feeders to critical customers
   3) Other main feeders
   4) Undamaged primary
   5) Damaged primary, secondary, service, street lights, security lights

These guidelines are not intended to prevent responding to emergency situations. Any life threatening emergency will be handled immediately, in such a manner as to not endanger the lives of others.

Each employee and contractor should maintain good customer relations during restoration activities. Customer service will continue to be a high priority and every reasonable effort should be made to satisfy our customers.

Press releases and public announcements should be made only by designated company management personnel.

5. EMERGENCY ELECTRIC SAFETY PRECAUTIONS

All Rules in the Safety Manual should be observed. However, in order to point out some particular precautions which should be observed during storms, the following instructions listed below should receive special emphasis:

ALL incoming crews must have a safety briefing as soon as practical upon arrival. This will be to introduce them to our system and inform them of our expectations.

A. SIZING UP WORK:

Before undertaking any job, a job briefing should be thoroughly discussed and all personnel should understand what is to be done, how it is to be done, and the following:

1. Voltage and position of all wires, or cables, and the sources or source of energy.
2. That the work at hand can be done safely.
3. That there is a sufficient amount of each kind of protective equipment on hand to thoroughly protect the working position and the work man.
4. They should consider the ground and traffic conditions and arrange to protect and guard these against all hazards.

B. INSULATION:

In cases of trouble following storms, all wires, regardless of normal voltage, are to be considered as being at primary voltage and are not to be handled except with protective equipment because of danger of crosses between primary and secondary circuits.

C. DISTRIBUTION CIRCUITS ON OR NEAR TRANSMISSION POLES:

If it is necessary to work on the conductors of a distribution circuit carried on or near transmission line poles with the transmission circuit energized and normal, any work on the conductors of the distribution circuits must be done between sets of grounds or else the distribution circuit must be worked and treated as an energized circuit. To determine positively that the lines to be worked are de-energized, test or investigation must be made before grounds are applied.

If the transmission line is also out of service and apparently in trouble, it must be considered as a possible source from which the distribution circuit may be energized, and it must be definitely determined that the transmission circuit as well as the distribution circuit is de-energized and grounded and the source or sources of supply are open and proper clearance obtained before the distribution circuit may be worked as de-energized.

D. STREET LIGHTING WIRES:

Street lighting wires shall be considered energized at all times and the workman shall protect himself against them with proper protective equipment even when circuits are normally de-energized. Such a line is liable to become energized by accidental induction or lightning and sometimes street lighting wires become crossed with other energized wires.

E. FUSE CUT-OUT CLEARANCE:

When a distribution circuit is to be de-energized and cleared for working on conductors or other equipment by the opening of a fuse cut-out, either of the enclosed or open type, the fuse holder or tube is to be removed completely from the fuse assembly. The removed fuse holder or tube is to be placed at a safe and conspicuous location away from the fuse cut-out as an indication to other employees that the fuse cut-out shall continue in this open position until the work is completed. In addition, a red "hold" switch tag (with Lineman's name) should be attached to the pole in a conspicuous location and then removed when work is completed.

F. REQUIREMENTS FOR USE OF RUBBER PROTECTIVE APPARATUS:

In case of trouble following storms, all wires, regardless of normal voltage, are to be considered as being at primary voltage and are not to be handled except with protective equipment because of danger of crosses between primary and secondary circuits.

1. Energized Conductors - Rubber gloves must always be worn when working on energized lines or energized conductors or equipment up to 15,000 volts between conductors.

2. Working position - Rubber gloves must be put on before coming in reach of energized conductors when work is done on conductors or protective equipment is to be installed.

Because of the possibility of high voltage existing, rubber gloves must be worn until the conductor is grounded on primary circuits and on street lighting circuits.

Care of Rubber Protective Apparatus - At each job, before a workman puts on his rubber gloves, he should test each glove mechanically for cuts and weak spots by rolling it up tightly, beginning at the gauntlet. All of this type equipment, when not in use, must be stored in dry proper containers or compartment provided for this purpose.

G. SWITCHING ORDERS:

In all switching orders, the switches shall be referred to by their numbers and not by the name of the circuit which they control. The sequence, in which the switch numbers are given, in the order, shall indicate the sequence of the switching operation. For example, an order given: "open switches 502-509 and close switches 511-502" shall be executed as follows: first, open switch 502; second, open switch 509; third, close switch 511; fourth, close switch 502.

NO DEVIATION FROM THIS RULE WILL BE PERMITTED.

To avoid misunderstandings and to prevent accidents, all orders concerning switching operation or the handling of lines and equipment must be repeated to the person giving name, and identity of person giving order secured. Likewise, the operator giving an order must secure identity of person to whom it is given. (three part communication)

H. SWITCHING ORDER:

All switching orders must be written on a piece of paper by the person receiving same, and this written order must be carried by the person while doing the switching. ***In no case shall anyone attempt to execute a switching order from memory.***

I. HIGH WATER:

During periods of high water involving lines or equipment, patrolmen shall not attempt to swim sections of the patrol which may be submerged. Necessary patrols over flooded areas must be done with boats and in such instances men engaged in these patrols shall wear suitable life belts or jackets.

J. BROKEN CONDUCTORS:

Before climbing pole, check for broken conductors, which may be in contact with pole. Clear before climbing.

6. ANNUAL PREPARATIONS

Electric Operations Manager

A. Review emergency procedure prior to May 1 and update as necessary.

B. Review employee assignments with all personnel prior to June 1.

C. Update status of emergency crew assistance (Contractors, NW Florida, SEE, etc.).

D. Schedule and conduct half day emergency procedure training sessions prior to July 1. Written documentation is to be retained when training is complete.

E. Ensure storm shutters, laundry facilities and cooking facilities are available.

Assistant Electric Operations Manager

A. Check all communication equipment for proper operation. Check spare equipment and parts.

B. Check material quantities and emergency stock prior to June 1. Begin necessary purchasing of emergency stock approved for purchase prior to an emergency.

C. Review safety precautions with all line crew personnel prior to June 1.

D. Have necessary emergency material delivered prior to June 1.

E. Review status of all transportation equipment and have repairs made.

F. Update status of remote storeroom site and trailer(s).

G. Update status of emergency fuel suppliers, on site fuel and mobile fuel suppliers.

H. Update status of vehicle repair facilities.

Propane Operations Manager

A. Check all communication equipment for proper operation. Check spare equipment and parts.

B. Check material quantities and emergency stock prior to June 1. Begin necessary purchasing of emergency stock approved for purchase prior to an emergency.

C. Review safety precautions with all propane personnel prior to June 1.

D. Have necessary emergency material delivered prior to June 1.

E. Review status of all transportation equipment and have repairs made.

F. Update status of emergency fuel suppliers, on site fuel and mobile fuel suppliers.

G. Update status of vehicle repair facilities.

Natural Gas Operations Supervisor

A. Check all communication equipment for proper operation. Check spare equipment and parts.

B. Check material quantities and emergency stock prior to June 1. Begin necessary purchasing of emergency stock approved for purchase prior to an emergency.

C. Review safety precautions with all natural gas personnel prior to June 1.

D. Have necessary emergency material delivered prior to June 1.

E. Review status of all transportation equipment and have repairs made.

F. Update status of emergency fuel suppliers, on site fuel and mobile fuel suppliers.

G. Update status of vehicle repair facilities.

Customer Care / Logistics Manager

A. Update the list of critical customers by town/county. Group the critical customers by town/county by classification:

1) Hospitals and clinics
2) Public utilities
3) Municipal and state emergency service
4) Communication and broadcasting services
5) Major food storage/processing facilities
6) Disaster shelter and motels
7) Correctional facilities
8) Airport

B. Update phone list for employees, law enforcement, emergency management, city/towns, utilities, contractors, tree trimming, personnel, news media, PSC, DCA, EDC, GEO, etc.

C. Review emergency telephone arrangements and make additional preliminary arrangements.

D. Update status of thirty (30) motel rooms necessary for emergency/contract crews.

E. Locate sources of food/water for crews and office personnel. Identify local and out of town caterers.

F. Update status of building security firm.

G. Locate sources for provision of the following Division office supplies.

1. Three days' supply of food and water. (See section 22, Logistics for List of Supplies)
2. Supply of air mattress/cots.
3. Portable AM/FM radios with batteries.
4. Laundry services/supplies.
5. First aid supplies.
6. Twenty (20) flashlights with batteries.
7. Linen service.
8. Miscellaneous supplies post storm shelter.

H. Update status of ten (10) cellular phones.

I. Update the procedure of the Office Operation.

Engineering

A. Update and have on hand the following:

1. Storm safety precautions
2. General operating instructions
3. Distribution maps
4. Single line switching maps
5. City and county maps

B. Have control room and all necessary information and equipment ready for prompt setup. Phone jacks, internet connection and distribution map are minimum requirements.

C. Conduct annual refresher training for personnel required to operate the Customer Outage System.

7. INITIATE STORM MODE PLAN

Electric Operations Manager

A. Monitor the emergency.

B. Begin making preparations for obtaining emergency assistance from other utilities and contractors.

C. Check the status of personnel on vacation.

D. Handle all media request by relaying contact information to Aleida, Bonnie or Mike.

E. Inform all employees as to assignments and emergency information.

F. Consult with the Executive Team concerning activation of Division Emergency Procedures.

G. Consult with Executive Team concerning assistance from other divisions (i.e. mechanics, storeroom, media, family assistance, IT/Communications). Personnel from other divisions will be identified and mobilized. They will move as close as practical to Northeast Florida and then proceed to the office as soon after the emergency as travel can be accomplished safely. This location may change dependent upon the situation.

H. Obtain special job number for all emergency related work.

I. Make determination on when to release personnel to go home and provide instructions to employees.

J. Ensure contact with JEA is established.

Assistant Electric Operations Manager

A. Have all vehicles stocked with all necessary emergency materials and fuel.

B. Monitor time/material needs of contractors.

C. Check emergency stock levels and fuel supplies.

D. Review plan to supply power to office and warehouse facility.

E. Check all communication equipment.

F. Review safety precautions with all personnel.

G. Review job assignments with personnel and pass out necessary forms, information.

H. Have all hazardous conditions corrected and construction jobs stabilized.

I. Verify emergency generator is fully fueled and operable with back-up fuel available.

J. Make arrangements for a boat and trailer suitable for construction.

K. Ensure all vehicle repairs are made and final arrangements with vehicle repair facilities confirmed.

L. Check on emergency generators and secure additional generators if needed.

M. Secure all material in the warehouse yard.

Propane Operations Manager

A. Have all vehicles stocked with all necessary emergency materials and fuel.

B. Monitor time/material needs of contractors.

C. Check emergency stock levels and fuel supplies.

D. Review plan to supply power to bulk plant using backup power supplies.

E. Check all communication equipment.

F. Review safety precautions with all personnel.

G. Review job assignments with personnel and pass out necessary forms, information.

H. Have all hazardous conditions corrected and construction jobs stabilized.

I. Verify emergency generator is fully fueled and operable with back-up fuel available.

J. Ensure all vehicle repairs are made and final arrangements with vehicle repair facilities confirmed.

K. Secure all material in the warehouse yard.

L. Install Storm Shutters on all offices with the help of natural gas.

M. Place plastic covering over all electronic or sensitive equipment and secure as necessary.

Natural Gas Operations Supervisor

A. Have all vehicles stocked with all necessary emergency materials and fuel.

B. Monitor time/material needs of contractors.

C. Check emergency stock levels and fuel supplies.

D. Review plan to supply power to bulk plant using backup power supplies.

E. Check all communication equipment.

F. Review safety precautions with all personnel.

G. Review job assignments with personnel and pass out necessary forms, information.

H. Have all hazardous conditions corrected and construction jobs stabilized.

I. Verify emergency generator is fully fueled and operable with back-up fuel available.

J. Ensure all vehicle repairs are made and final arrangements with vehicle repair facilities confirmed.

K. Secure all material in the warehouse yard.

Customer Care / Logistics Manager

A. Arrange for additional petty cash and cash advances (if necessary).

B. Arrange with telephone company additional lines if necessary.

C. Review assignments with personnel.

D. Ensure all computers are backed up and secured.

E. Ensure all paperwork/documents are filed and secured properly.

F. Provide control room with customer list, addresses, phone numbers and account numbers.

G. Work with HR department and personnel from other divisions to provide assistance to employees and their families. Assistance may include work to prevent further damage to homes, care for children, to work with contractors or insurance companies and provide food/lodging/clothing, etc.

H. Make definite arrangements for contract crew lodging.

I. Make definite arrangements for food/water/drinks for all personnel.

J. Purchase food supply for office/warehouse prior to storm (if the severity of the storm warrants this).

K. Run the hurricane report from ORCOM.

L. Make arrangements for an abundant supply of ice.

M. Make definite arrangements for building security.

N. Make definite arrangements for Division Office supplies (See Annual Preparations, Logistics Manager, and Item E.)

O. Place plastic covering over all electronic or sensitive equipment and secure as necessary.

Engineering

A. Provide distribution maps, procedures, etc. as necessary.

B. Ensure Mapping System is backed up and operating.

C. Begin constant monitoring customer outages.

8. INITIAL STAGE OF THE EMERGENCY

Electric Operations Manager

A. Be located at the Northeast Florida Operations Center (if possible) and constantly monitor the situation and restoration process.

B. Keep internal media sources informed.

C. Plan for additional services that will be needed during the restoration process to include damage assessment teams and mutual assistance crews.

D. Activate control room.

Assistant Electric Operations Manager

A. Be located at the Northeast Florida Operations Center (if possible) and constantly monitor the situation and restoration process.

B. Coordinate overall restoration process.

C. Begin analyzing trouble.

D. Ensure employees that may be working are secure when wind gusts reach 40 miles per hour.

E. Work with Operations Manager to determine restoration requirements.

Propane Operations Manager

A. Be located at the Northeast Florida Operations Center (if possible) and constantly monitor the situation and restoration process.

B. Activate propane restoration process.

C. Coordinate with Engineering.

Natural Gas Operations Supervisor

A. Be located at the Northeast Florida Operations Center (if possible) and constantly monitor the situation and restoration process.

B. Activate propane restoration process.

C. Coordinate with Engineering.

Customer Care / Logistics Manager

A. Be located at the Northeast Florida Operations Center (if possible) and coordinate the answering and processing of telephone calls.

B. Coordinate assistance to employees and their families.

C. Have food and drinks available to all employees.

D. Work with Operations Manager and begin making final logistical arrangements for outside crews.

Engineering

A. Be located at the Northeast Florida Operations Center (if possible) and Continue processing customer outage system analysis and monitoring system to determine outage locations.

B. Work with Operations Manager to determine restoration requirements.

C. Provide periodic outage updates to the PSC and Nassau County EOC.

9. LOCAL STORM MODE

Storm Director

A. Determine manpower requirement from information provided by Operations Director and Engineering Director. Contact the Executive Team concerning the situation, if possible, and advise whether or not the additional personnel should continue to the Northeast Florida office. If communications are not possible, the President will determine whether or not the team should continue to Northeast Florida or will return home. .

B. Activate additional services that will be needed during the restoration process to include damage assessment teams and mutual assistance crews.
C. Keep the media informed until such time that the Manager of Communications is available. At that time, the Manager of Communications will work with the Storm Director to keep the Media informed.

Operations Director

A. Initiate damage assessment teams.

B. Prioritize and schedule the restoration process.

C. Make assignments and dispatch crews as necessary in order to ensure orderly and efficient restoration.

D. Provide damage assessment to Storm Director.

E. Provide updates to Storm Director as needed concerning restoration progress.

F. Monitor manpower and equipment requirements and update Storm Director as required.

G. Keep a list of all company and outside crews and their locations.

H. Determine and assign appropriate manpower and equipment for each outage situation.

I. Provide outside crews with all necessary information and safety information.

J. Monitor storeroom and remote storeroom for proper operation and inventory. Analyze manpower requirements.

K. Ensure all documents are completed prior to material leaving the storeroom and storeroom yard.

L. Monitor and provide assistance in repairing vehicles.

Propane Operations Manager

A. Make assignments and dispatch crews as necessary in order to ensure orderly and efficient restoration.

B. Provide damage assessment to Storm Director.

C. Provide updates to Storm Director as needed concerning restoration progress.

D. Monitor manpower and equipment requirements and update Storm Director as required.

E. Keep a list of all company and outside crews and their locations.

F. Determine and assign appropriate manpower and equipment for each situation.

G. Provide outside crews with all necessary information and safety information.

L. Monitor and provide assistance in repairing vehicles.

Natural Gas Operations Supervisor

A. Make assignments and dispatch crews as necessary in order to ensure orderly and efficient restoration.

B. Provide damage assessment to Storm Director.

C. Provide updates to Storm Director as needed concerning restoration progress.

D. Monitor manpower and equipment requirements and update Storm Director as required.

E. Keep a list of all company and outside crews and their locations.

F. Determine and assign appropriate manpower and equipment for each situation.

G. Provide outside crews with all necessary information and safety information.

L. Monitor and provide assistance in repairing vehicles.

Customer Care / Logistics Director

A. Coordinate the answering of telephone calls.

B. Provide petty cash and pay bills as needed.

C. Contact critical customer if the restoration time will be lengthy.

D. Provide assistance and serve as liaison to employees and their families.

E. Make final and definite arrangements for lodging, fuel, meals, snacks, coffee, drinks, etc. for all employees and contract employees.

F. Check-in all outside crews and log the personnel and equipment included. Provide assistance with lodging, meals, etc. and keep up with crew locations.

G. Provide assistance as needed.

H. Ensure building security firm is operating at office.

I. Ensure Division office supplies are in place if needed.

J. Ensure caters are available as needed.

Engineering Director

A. Continue processing customer outage system analysis and monitoring the system to determine outage locations.

B. Work with Storm Director and Operations Director to determine restoration requirements.

C. Provide periodic outage updates to the PSC and Nassau County EOC.

10. Operating Procedure

These instructions are intended to give the employee working on the line information as to the general procedure to be followed under hurricane conditions.

The Electric Operations Manager and Customer Service Manager will review these instructions with their employees each year so that they may become familiar with the details. This should be done before July 1of each year.

A. BEFORE THE STORM

All operating personnel should be instructed as to:

1. Safety and operating procedures to be followed during the storm.
2. Where and when materials and supplies will be available.
3. Their assigned areas and supervisor.
4. Any provisions made for feeding and lodging.
5. Work days will normally be two shifts. Each shift will consist of at least 12 hours but could be 16 hours.
6. The necessity of dividing line crews for clearing and minor repairs.
7. Internet and telephone communication procedures with appropriate list of telephone numbers.

B. DURING THE STORM

1) First Stage - Repairing All Cases Reported

In order to reduce the over-all outage time to customers who may be interrupted at the beginning of the storm, trouble will be handled in a normal manner during the early stages.

2) Second Stage - Clearing Trouble From the Lines

In order to maintain service to essential customers and feeders; when the volume of trouble increases to the point where large areas are interrupted, the Supervisor will instruct crews to clear trouble from the lines without making repairs.

a. Secondary or service wires may be cleared by cutting the conductor away from energized lines or by opening the transformer cut-out.

b. Damaged primary conductors may be cleared by cutting and rolling back, a primary jumper or conductor at the cross arm or by sectionalizing switching, if applicable.

3) Third Stage - De-energizing Main Lines

When the winds reach the point where it is no longer safe for crews to continue clearing operations all restoration activities will cease. The Line Supervisor may instruct crews to de-energize main line feeders at substations if necessary to clear extremely hazardous conditions.

C. AFTER THE STORM

1) Sequence of Restoration

The sequence of restoration after the winds subside to a safe working level will be as follows:

a. Transmission
b. Substations
c. Essential customers

d. Feeders
e. Undamaged primaries (fuse replacement only)
f. Damaged primaries
g. Secondaries
h. Services
i. Street lights

2) Line Patrols

To prevent further damage, all distribution lines, which have "locked out" due to the storm, must not be re-energized until patrolled and cleared of primary faults.

11. TELEPHONE OPERATORS GUIDE

During any major interruption our customers will naturally be concerned about falling wires, burning wires, defrosting refrigeration and even their daily routines in which electricity plays a part. The most important test we have is maintaining good relations during these emergencies. Those employees answering telephones must keep this in mind - be calm, pleasant and sympathetic with the customer and at the same time getting the necessary information needed to clear dangerous conditions and restore service as soon as possible, giving as much information to the customer that is available.

Outlined below is a suggested procedure to be used during three different phases of an interruption (The Director of Electric or Electric Operations Manager will determine when Phase 1 begins and when movement to Phase 2 and 3 is indicated):

Phase 1 - will be in effect until the time of the first trouble calls are worked or until it is evident that there is a widespread damage in that area.

Phase 2 - will be in effect following Phase 1 until damage evaluations have been made and estimate of the time required for making major repairs.

Phase 3 - will begin in an area where an estimate of the time required to make major repairs is available and will continue until all trouble is clear.

Your supervisor will advise you when conditions change from one phase to another in accordance with the routines outlined below:

Suggested Answering Routine to be used by All Operators

Phase 1 - Early Trouble Prior to Extensive Damage

1. "Florida Public Utilities, May we help you please."
   a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"
   b. If wire down, pole broken, tree on a line, ask:
      1) "Is the wire burning?"
      2) "Are your lights working?"
      3) "We hope to be able to make repairs shortly. Thank you very much for calling."

Phase 2 - Extensive Damage Evident But Estimate of Repair Time Not Available

1. "Florida Public Utilities, May we help you please."

a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"

b. If wire down, pole broken, tree on a line, ask:
   1) "Is the wire burning?"
   2) "Are your lights working?"
   3) "Our electric system has suffered considerable damage in your area and we haven't been able to make an estimate of the time required for repairs. Our crews are working now and if your service has not been restored by (morning/afternoon) please call again. Thank you."

Phase 3 - Damage Evaluated and Repair Time Estimated

1. "Florida Public Utilities, May we help you please."

   a. If no lights, no power, lights dim, ask: "What is your name, address and telephone number please?"

   b. If wire down, pole broken, tree on a line, ask:

      1) "Is the wire burning?"
      2) "Are your lights working?"
      3) "We have crews working on the lines which serve your area and repairs should be made by (time). If your electricity us not on by that time, please call again. Thank you."

Operators Guide

You will be relieved for meals, etc., and at the end of your shift.

Remember a properly handled telephone conversation with a customer can create an immeasurable amount of good will. When conversing with customers, keep the following points in mind:

1. Be courteous to each customer.
2. Give him/her as much information as is available of the restoration work.
3. Record each call and report the information vital to restoring the customer's service.
4. Handle each call as briefly as possible.
5. Thank the customer for calling.
6. Do not give the news media information. If a request for new information is received, record the name of the individual, news organization, telephone number and specific request. Inform the caller that a company representative will return the call. The information should be sent immediately to the Electric Operations Manager, Northeast Florida.

7. During an emergency condition, some customers will contact the company for reasons that do not pertain to the emergency. These calls should be recorded and the exact customer needs should be stated in the remarks column. These calls may include disconnections, reconnections, etc., or may be a personal call to an employee. After the contact has been recorded, the completed form should be given directly to the supervisor.

Entering Outages

Each customer call will be recorded in the Outage Management System (OMS). The information entered should be entered accurately to ensure the system operates properly. The information entered will be stored as a permanent record and will be used to analyze the nature of the outages.

Should emergency situations come to your attention, please notify a supervisor. The method of this documentation will be determined.

12. MEDIA/PUBLIC INFORMATION GUIDE

In order to monitor all information given to media and public sources, only the Electric Operations Manager, Northeast Florida, Manager of Communications or their designee will make press releases. If other employees are asked by media or public agencies for information, politely ask them to contact the Electric Operations Manager, Northeast Florida or Manager of Communications for the latest information.

13. WAREHOUSE PROCEDURE

During an emergency, material is vital to promptly and efficiently restore service to all customers. It is therefore important to monitor all stock levels to ensure adequate supplies are on-hand and if stock levels get low, be able to quickly order additional materials.

All material taken from the storeroom or remote storeroom will have the appropriate documentation completed before being removed from the stores area. The stores personnel will ensure this is followed.

Only authorized personnel should be in the stores area. Stores personnel will monitor those in the stores area to ensure compliance.

14. OFFICE PROCEDURE

This section will involve that information and other procedures necessary to ensure that the Office operation continues to operate during any emergency that may occur.

Annual

1. The Customer Service Manager will update information regarding the Office operations.
2 Information about the contingency plan will be updated by the Customer Service Manager each year.

Prior to the Emergency

1. The Electric Operations Manger and Customer Service Manager will decide on the appropriate contingency plan necessary based on the emergency situation and begin contingency operations.
2. The Customer Service Manager will ensure that protective covering is available and installed on all Office equipment and server to ensure damage, if any, is minimized.

After the Emergency

Contingency Plan #1

1. Due to the damage to the NE FL facilities, all mail and payments will go directly to the Northwest Florida office. This may not be the best alternative due to the issues with the USPS but is the most practical.

2. NW Florida personnel will process the mail using personnel as needed. Deposits will be made normally on a daily basis.
3. As soon as NE FL is capable of processing payments normally, payment processing will be handled normally.

Contingency Plan #2

1. Due to the inability of the Corporate Office to accept updated information from the Office, it will be necessary to send payment information to a remote location.
2. NE FL will continue to process payments normally and make deposits accordingly.
3. The IT Director will provide NE FL with the appropriate directions on where to send the information concerning payments. This information will be added to this procedure when it becomes available.
4. All information on payments will be saved to a CD on a daily basis and stored in a safe place. If possible a hard copy of the information should also be printed and stored in a safe place.

15. Personnel Backup Contingencies

Should the following personnel not be available during the emergencies, personnel in the positions listed below that position will fill in as needed.

Director of Electric
Electric Operations Manager

Electric Operations Manager
Assistant Electric Operations Manager

Propane Operations Manager
Natural Gas Operations Supervisor

Engineering
Technical Projects Manager

Customer Care Manager
Customer Care Supervisor

16. EMPLOYEE ASSIGNMENTS

TENTATIVE SCHEDULE

DAY SHIFT
Begin at 6:00 AM

OFFICE

Buddy Shelley	
Bill Grant	Electric Operations Mgr.
Jorge Puentes	Technical Projects Mgr.
Mark Cutshaw	Technical Projects Director
Roger LaCharite	Customer Service Manager
Greg Blazina	Propane Manager
Mary Atkins	Engineering
David Richardson	Logistics
Linda Winston	Logistics
Rena Williams	Telephone
Linda Gamble	Telephone
Renee Bolyard	Telephone
Waldron Hamilton	Telephone
Susan Beale	Telephone

LINE CREWS

Rich Crigger	Assistant Elect Ops Mgr.
Steve Taylor	Senior Lineman
Clint Brown	Senior Lineman
Billy Clardy	Crew Leader
Donnie Maxwell	Lineman
Parrish Kildow	Senior Lineman

SERVICE CREWS

Al Harris	Senior Lineman
Vacant	Lineman
Dean Montgomery	Lineman
Justin Beverly	Lineman
Jeff Hindsley	IMC Tech
James McDaniel	IMC Tech

STORES

Roger Reed (FR)	Stores Supervisor
Randy Moore (FR)	Warehouse Assistant

PATROLMAN/GUIDE

Lewis Peacock	Patrolman/Guide
Sarah Davis	Patrolman/Guide
Brandy Baldwin	Patrolman/Guide

NIGHT SHIFT
Begin at 6:00 PM

OFFICE

Patti Thornton	Customer Care Supervisor
Mia Goins	Telephone
Leslie Zambrano	Telephone
Lynn Britton	Logistics
Curtis Boatwright	Engineering
Chris Hebert	Engineering

SERVICE CREWS

Shannon Wagner	Crew Leader
Vacant	Apprentice

OFFICE/PATROLMAN/GUIDE

Jevon Brown	Telephone/Patrolman

PROPANE OPERATIONS

Vacant	Service Tech. B
Terry Simmons	Gas Utility Worker

NATURAL GAS OPERATIONS

George Speerin	Supervisor
Rod Calhoun	Service Tech

DAY SHIFT (CONTINUED)

Begin at 6:00 AM

Natural Gas Operations

Cedric Mitchell	Service Tech

PROPANE OPERATIONS

Dave Pluta	Service Tech. A
James Moore	Service Tech. B
Jody Montgomery	Gas Utility Worker

SAFETY

Tom Moen	Safety, Training & Compliance

17. EMERGENCY ASSISTANCE LIST

Company	Contact	Telephone	Available Resources
Southeast Electric Exchange	Scott Smith	**(404) 233-1188** **(404) 357-6800 cell**	Crews
	Jim Collins	(404) 229-2301 cell	
FPU-Marianna	Lynwood Tanner	(850) 209-3409	Crews, Tree Crews, Support
	Jerry Lewis	(850) 209-8898	
ATT	Scott Miller Marvin Fisher	(904) 407-2569 (904) 238-8263 cell (904) 727-1544 (904) 403-1894	Engineering Engineering
Comcast	Mike Jackson	(904) 626-2400 1-855-962-8525..3..1..HFC	Day contact After hours answering serv.
Quantas/Dillard Smith	Brian Imsand	(423) 490-2206	Crews
Pike Electric Coop	Barry McCarthy bmccarty@pike.coi	(912) 258-0645 cell (850) 632-5769 home	Crews
Public Service Commission	Rick Moses (EOC)	(850) 431-6582 (850) 408-4757 cell	Primary contact
PSC	Tom Ballinger	(850) 413-6680	Backup contact
Florida Electric Power Coord Group	R J Midulla	(813) 289-5644	Crews
Mastec	Ron Martin	(904) 562-2135	Crews
C & C Powerline	Rick Springer rick@ccpowerline.(	(904) 751-6020 (904) 759-4703	Crews
Davey	Mike Mittiga	(407) 383-0648 mobile	Tree Crews
Asplundh	Ronnie Collins	(352) 256-2370 cell	Tree Crews
JEA	Dispatcher	(904) 665-7152	Power Supply
Vehicle Repairs Assistance			
Company	**Contact**	**Telephone**	**Available Resources**
Altec	Bobby Knittel	**(352) 303-3894**	Service Technician Supervis
Altec	Bobby.knittle@altec.com	1-877-462-5832	
Altec	Joe Osheim cell	(205) 458-3445 (229) 375-9696	Mobile Service Tech
Auto Masters Fleet Services	David Stringfield Gary Sunley Rey Marquez	(904) 716-1601 (904) 838-3038 (904) 483-5449	Owner Sales Manager Vice President
Carter Auto	Tommy Carter	(904) 491-8255	Repairs and Tires
First Coast Fab.	Doug Wolf	(904) 261-7611	Welding And Machine Work
General Truck	Howard Johnson	(904) 588-5423	Crane Repairs and Parts
Maudlin International Trucks	Jerry Green Jason Correia	(904)509-0012 (904) 783-9822	Truck repairs and Parts Service Manager
Moeller	George Moeller	(904) 415-2094	Vehicle Repairs and Welding
Napa	Tom Cox	(904) 261-4044	Parts and Tools
Power Pro-Tech	Jimmy Evans	(800) 437 4474	Generator Repairs
Generator & HVAC Service	James Stamper **Onsite Emergency**	1-800-437-4474 321-274-8578 **888-218-0298** **678-566-2439**	8th and Lime locations **780 Amelia Island Pkwy**
Tiresoles	Scott McAlpine Pat Demianenko	(904) 378-0090 (954) 354-1810 Cell (904) 610-9498	Main Office Operations Manager

18. EMERGENCY STOCK REQUIREMENTS

See next 4 pages

Bin#	Description	Qty Required	Qty On Hand	Order *
31-1065	WIRE,#8 BARE SOL SD CU TIE WIRE (SPOOL)	1000	2500	---
31-1095	WIRE,#6 CU SD SOLID POLY,TX RISER WIRE (SPOOL)	1000	750	3000
31-1115	WIRE,#4 BARE SOL CU SD OH (SPOOL)	1000	990	2000
31-1310	WIRE,#4 AL OH SOFT TIE (SPOOL)	1000	2616	---
31-1350	WIRE,1/0 BARE STD AL OH (AZUSA)	1000	10535	---
31-1410	WIRE,4/0 BARE STD AL OH (ALLIANCE)	1000	23686	---
31-1460	WIRE,396.4 BARE STD AL OH (CANTON)	1000	12625	---
31-1470	WIRE,#477 BARE STD AL OH (COSMOS)	1000	5564	---
31-1475	WIRE,#636 BARE STD AL OH (ORCHID)	1000	9742	---
31-1479	WIRE,#2 AL DUPLEX OH (DOBERMAN/XLP)	1000	9500	---
31-1480	WIRE,#6 AL DUPLEX OH (COIL)(SHEPPARD)	600	1850	---
31-1580	WIRE,1/0 TRIPLEX OH (COIL)(GAMMARUS)	1000	3000	4000
31-1585	WIRE,1/0 TRIPLEX OH (REEL)(GAMMARUS)	1000	5650	---
31-1610	WIRE,4/0 STD TRIPLEX AL OH (LAPAS)	500	1125	---
31-1660	WIRE,1/0 QUAD AL OH (SHETLAND)	200	990	---
31-1715	WIRE,GUY 3/8 BEZINAL COATED	1000	2500	---
33-1030	WIRE,#2 AL URD 15KV	3000	6960	---
33-1050	WIRE,4/0 INS STD AL URD 15KV	6000	11230	---
33-1070	WIRE,750MCM AL URD 15 KV	3000	5292	---
35-1040	ANCHOR SCREW 5' X 10"	10	61	---
35-1050	ANCHOR SCREW 8' X 10"	10	37	---
35-1145	ARRESTOR,LIGHTNING,SILICONE 9 KV	20	64	---
35-2060	BRACKET, MOUNTING, AL ONE CUTOUT & ARRES.	20	24	30
35-2065	BRACKET,MOUNTING,AL	20	40	---
35-2075	BRACKET, SINGLE INSUL, FIBERGLASS, HORIZ	20	39	---
35-2080	BRACKET,MOUNTING,AL HEAVY DUTY	10	15	---
35-2310	CLAMP,GROUND ROD 5/8"	20	269	---
35-2650	COUPLING GROUND ROD 5/8, CU CLAD(NON-THREAD)	50	157	100
35-2661	COVER,SERVICE SLEEVE #C2	200	810	---
35-2662	COVER,H-TAP #C5	200	362	200
35-2663	COVER,H-TAP #C7	200	238	200
35-2716	CUTOUT,SILICONE,SEACOAST	50	56	42
35-2717	FUSEHOLDER,200A CUTOUT	20	26	---
35-2718	FUSEHOLDER,100A CUTOUT	10	11	25
35-2835	GUARD,LINE 336.4 MCM AL OR ACSR	30	61	---
35-2840	GUARD,LINE 477 MCM AL OR ACSR	30	49	---
35-2855	GUARD,SQUIRREL	10	60	25

35-3014	INSULATOR,UPRIGHT 35 KV SILICONE	30	100	48
35-3025	INSULATOR,HORIZ MOUNT 35KV SILICONE INT BASE	60	71	96
35-3040	INSULATOR,POST TYPE 88KV W/CLAMP	12	20	---
35-3085	INSULATOR,SUSPENSION SILICONE 25 KV	20	31	36
35-3120	INSULATOR,GUY STRAIN 8 FT	10	13	20
35-3121	INSULATOR,GUY STRAIN 8 FT 36000 LB	10	105	---
35-3245	MOUNT,TX,BRACKET, SINGLE PHASE	10	25	---
35-3260	MOUNT,TX CLUSTER AL ABOVE 3-50KVA	4	6	---
35-3520	POLE,30 CL 6 CP	15	18	
35-3530	POLE,35 CL 4 CP	10	14	5 day
35-3545	POLE,40 CL 3 PP	10	13	
35-3550	POLE,40 CL 1 PP	15	19	
35-3575	POLE,45 CL 3	15	9	---
35-3579	POLE,45 CL H1	5	5	---
35-3590	POLE,55 CL H1	1	6	---
35-3760	ROD-GROUND COPPER CLAD 5/8" X 8' NON-THRD	30	404	---
35-3945	SWITCH,UNDERSLUNG	6	8	---
35-3946	SWITCH,INLINE	6	14	---
37-1000	CLAMP,DEADEND,#6-#4 AL SERVICE WEDGE	20	181	---
37-1020	CLAMP,DEADEND,#2-1/0 AL SERVICE WEDGE	40	88	200
37-1040	CLAMP,DEADEND,4/0 AL SERVICE WEDGE	40	147	200
37-1250	CLAMP,PARA GR #2 STD AL	50	181	---
37-1260	CLAMP,PARA GR #1/0 STD AL W/SS BOLTS	50	187	---
37-1270	CLAMP,PARA GR 4/0 STD AL	50	88	---
37-1290	CLAMP,PARA GR 350-477 AL OR 336-397 ACSR	50	120	---
37-1380	CONN,H-TYPE (WR9)	50	287	---
37-1390	CONN,H-TYPE (WR159)	100	247	---
37-1400	CONN,H-TYPE (WR189)	100	200	200
37-1415	CONN,H-TYPE (WR259)	100	150	200
37-1420	CONN,H-TYPE (WR379)	100	539	---
37-1425	CONN,H-TYPE (WR399)	100	264	250
37-1430	CONN,H-TYPE (WR419)	100	79	100
37-1455	CONN,H-TYPE (NB500-40)	30	224	---
37-1456	CONN,H-TYPE (NB500)	30	126	---
37-1620	CONN,VISE ACTION #6 CU	100	593	---
37-1630	CONN,VISE ACTION #4 CU	100	202	400
37-1640	CONN,VISE ACTION 6 SOL-#2 SOL CU	100	702	300
37-1650	CONN,VISE ACTION 2 SOL-#2 STD CU	100	522	500
37-1660	CONNECT-VISE ACTION 2/0 SOL -1/0 STD CU	100	206	450
37-1670	CONN,VISE ACTION 1/0 SOL-4/0 STD CU	100	101	350
37-1710	CONN,URD FLOOD SEAL 4 POSITION	30	38	---
37-1713	CONN,TX,OH,6 POSITION	25	166	---

37-1770	DEADEND,AUTOMATIC SS #2 STD CU	20	132	---
37-1780	DEADEND,AUTOMATIC SS 1/0 STD CU	20	48	---
37-1785	DEADEND,AUTOMATIC SS 2/0 STD CU	10	87	---
37-1790	DEADEND,AUTOMATIC SS 4/0 STD CU	20	107	---
37-1800	DEADEND,AUTOMATIC SS #2 STD AL	20	100	---
37-1810	DEADEND,AUTOMATIC SS 1/0 STD AL	20	56	---
37-1840	DEADEND,AUTOMATIC SS 4/0 STD AL	20	31	---
37-1850	DEADEND,AUTOMATIC SS 394.6 AL	20	82	---
37-1855	DEADEND,AUTOMATIC SS 477 AL	20	68	---
37-1891	DEADEND,FULL TENSION,COMP477 AL W/2 HOLE LUG	15	44	---
37-1892	DEADEND,FULL TENSION,COMPRESSION 636	15	18	---
37-1970	LUG,TERM,URD 2/0 AL 2-HOLE	50	100	---
37-1980	LUG,TERM,URD 4/0 AL 1-HOLE	50	222	---
37-2120	SLEEVE,AUTO SPLICE #8 STD-#6 SOL CU	20	64	---
37-2130	SLEEVE,AUTO SPLICE #6 STD-#4 SOL CU	20	59	---
37-2141	SLEEVE,AUTO SPLICE #2 STD CU	20	255	---
37-2161	SLEEVE,AUTO SPLICE 1/0 CU	20	241	---
37-2190	SLEEVE,AUTO SPLICE 4/0 STR CU	20	44	---
37-2340	SLEEVE,SERVICE 2/0-2/0 AL/ACSR (IKL47)	100	106	100
37-2350	SLEEVE,SERVICE 4/0-1/0 AL (IKL66)	100	178	---
37-2360	SLEEVE,SERVICE 4/0-2/0 AL (IKL67)	100	122	100
37-2370	SLEEVE,SERVICE 4/0-4/0 AL (IKL69)	100	133	---
37-2375	SLEEVE,SERVICE 350-350 AL	50	111	---
37-2430	SLEEVE,FULL TENSION #2 STD AL	20	256	---
37-2450	SLEEVE,SERVICE FULL TENSION 1/0 STD AL	20	195	---
37-2480	SLEEVE,PRIMARY FULL TENSION 4/0 AL	20	113	---
37-2515	SLEEVE,PRIMARY FULL TENSION 397.5(396.4)	20	29	---
37-2530	SLEEVE,PRIMARY FULL TENSION 477 AL	20	47	---
37-2535	SLEEVE,PRIMARY FULL TENSION 636 AAC	20	65	---
37-2665	SPLICE KIT,URD 15KV #2 STD AL	12	58	---
37-2670	SPLICE KIT,URD 15KV-2/0 AL	17	43	---
37-2680	SPLICE KIT,URD 15KV-4/0 AL	12	36	---
37-2690	SPLICE KIT,URD 15KV 750 AL	12	35	---
37-2820	TERMINAL,PIN #2STD AL	50	116	300
37-2830	TERMINAL,PIN 1/0 STD AL	50	220	---
37-2835	TERMINAL,PIN 2/0 STD AL	50	31	20
37-2840	TERMINAL,PIN 4/0 STD AL	50	80	---
37-2845	TERMINAL,PIN 350 AL	10	59	---
37-2850	TERMINAL,PIN 500 AL	10	64	---
39-1220	FUSE LINK 7 AMP QA	75	117	50
39-1240	FUSE LINK 15 AMP QA	50	167	---
39-1260	FUSE LINK 25 AMP QA	50	117	50
39-1270	FUSE LINK 30 AMP QA	75	137	---

39-1290	FUSE LINK 50 AMP QA	75	180	25
39-1320	FUSE LINK 75 AMP QA	25	69	25
39-1330	FUSE LINK 100 AMP QA	25	73	---
41-1114	KITS,TERM OH FOR 2/0 AL	10	38	---
41-1115	KITS,TERM OH FOR #2 AL	20	20	10
41-1120	KIT,TERM SILICONE FOR #2 AL	10	29	---
41-1125	KIT,TERM OH,SILICONE FOR 4/0 AL	20	27	---
41-1148	ELBOW,LOAD BREAK TERMINATOR #2 W/TEST POINT	20	64	---
41-1150	ELBOW,LOAD BREAK, URD, 2/0 AL,15KV W/TEST POINT	10	34	---
41-1160	TERMINATOR,LOAD BREAK 4/0 W/TEST POINT	20	107	---
41-1195	STRAP,MOUNTING,TERMINATOR,#2,2/0 & 4/0	50	67	---
41-1200	VAULT,SECONDARY,PEDESTAL	6	26	12
N/S	#2 Extended Repair Elbows	12	OK	---
N/S	#2/0 Extended Repair Elbows	12	OK	---
N/S	#4/0 Extended Repair Elbows	12	OK	---
N/S	EXTENDED SPLICE REPAIR KIT,#2 STR,3M QS II	5	6	---
N/S	EXTENDED SPLICE REPAIR KIT,2/0,3M QS II	10	14	---
N/S	EXTENDED SPLICE REPAIR KIT,4/0,3M QS II	5	8	---
NS 35-1185	ATTACHMENT,DOWN GUY	20	20	50
NS 35-1186	ATTACHMENT,DOWN GUY (POLE PLATE) WOOD 35MLB	10	OK	---
NS 35-1187	ATTACHMENT,DOWN GUY CONCRETE 35MLB	10	OK	---
NS 35-1350	BOLT,DOUBLE ARMING,GALV 5/8 X 18	30	OK	---
NS 35-1360	BOLT,DOUBLE ARMING,GALV 5/8 X 20	20	OK	---
NS 35-1430	BOLT,DOUBLE ARMING,GALV 3/4 X 22	20	OK	---
NS 35-1480	BOLT,DOUBLE UPSET,GALV 5/8 X 12	20	OK	---
NS 35-1640	BOLT,MACHINE,GALV 5/8 X 10	100	70	100
NS 35-1650	BOLT,MACHINE,GALV 5/8 X 12	100	20	200
NS 35-1660	BOLT,MACHINE,GALV 5/8 X 14	100	190	---
NS 35-1800	BOLT,MACHINE,GALV 3/4 X 20	50	OK	---
NS 35-1810	BOLT,MACHINE,GALV 3/4 X 22	50	OK	---
NS 35-1820	BOLT,MACHINE,GALV 3/4 X 24	50	OK	---
NS 35-1850	EYELET, 3/4" HOLE	50	75	400
NS 35-2245	CLAMP SUPPORT FOR #2,1/0,4/0 CU	50	OK	---
NS 35-2255	CLAMP SUPPORT FOR #2,1/0,4/0 AL	50	OK	---
NS 35-2265	CLAMP SUPPORT 394.6-477 AL	50	OK	---
NS 35-2375	CLEVIS,SECONDARY EXTENSION	20	OK	---
NS 35-2780	EYELET,THIMBLE ANGLE 5/8"	20	OK	25
NS 35-2895	GUY GRIP,3/8", BEZINAL COATED (352895)	100	10	200
NS 35-3130	LAG SCREW - 1/2"X4" GALV.	150	500	---
NS 35-3290	NUT EYE,GALV 5/8	30	30	50
NS 35-3300	NUT EYE,GALV 3/4	30	OK	---

NS 35-3320	NUT,THIMBLE EYE 5/8	20	OK	---
NS 35-3881	STRAP,CONDUIT OR PIPE 2" STAINLESS STEEL	40	OK	100
NS 35-3886	STRAP,CONDUIT OR PIPE 3" STAINLESS STEEL	40	OK	---
NS 35-3970	TAPE,SCOTCH #23-2	20	OK	---
NS 35-4020	TAPE,VINYL	50	OK	400
NS 35-4030	THIMBLE,GUY WIRE 3/8	200	OK	---
NS 35-4335	WASHER,DOUBLE COIL 5/8"	200	OK	---
NS 37-1865	DEADEND,AUTO,SLIDE OPENING WEDGE #4-4/0	50	OK	---
NS 37-1868	DEADEND,AUTO,SLIDE OPENING WEDGE 4/0-600	50	OK	---
	Transformer, Pad Mount 100 KVA	7	6	
	Transformer, Pad Mount 50 KVA	7	12	
	Transformer, Pad Mount 75 KVA	7	6	

*As of 5/5/10

19. TRANSPORTATION AND COMMUNICATION EQUIPMENT

Unit #	Tag / Mo.	Year	Model	Body Type	Dept. Code	Employee	comments
691A	GBP243	1982		Trailer	EL451	Reel Trailer	
692A	GBP172	1982		Trailer	EL451	Reel Trailer	
705A	GBP174	1992		Trailer	EL452	Equipment Trailer	
708A	GBP225	1998		Trailer	EL452	Equipment Trailer	
740	GBP672	1995	4700	Bucket	EL452	Parrish Kildow	
747	GBP673	1998	4800	Bucket	EL451	Donnie Maxwell	
754	GBP383	1999		Trailer	EL451	Reel Trailer	
755	GBP444	1999		Trailer	EL451	Reel Trailer	
763A	GBC971	2000		Trailer	EL452	Equipment Trailer	
774	GBP445	2001	Ranger	Comp. P/U	WH450	Roger Reed	
785	GBF903	2001		Trailer	MK412	BBQ Trailer	
786	GBC996	2002		Trailer	EL451	Lawn Maint Trailer	
790	GBP173	2003	CZ12KP	Trailer	EL451	Pole Trailer	
792	GBP902	2004	4300	Bucket	EL452	Steve Taylor	
795	K413CK	2006	Trail Blazer	SUV	CS411	Patti Thornton	
796	T004DR	2006	Silverado	Pickup	EL451	On-Call	
798	GA4363	2005	7400	Digger Derrick	EL452	Poles and transformers	
804	GBP667	2008	4300	Bucket	EL451	Billy Clardy	
810	GBP661	2011	4300	Bucket	EL451	Clint Brown	
811	GBC917	2010	F-150	Pickup	SM711	Tom Moen	
812	GBC945	2010	Ranger	Comp. P/U	EN450	Curtis Boatright	
813	693NVX	2010	F-150	Pickup	EL450	Jorge Puentes	
814	694NVX	2010	F-150	Pickup	EL451	~~Spare~~	
817	GBC976	2011	Ranger	Comp. P/U	EL452	Lewis Peacock	
818	GBC974	2011	Ranger	Comp. P/U	EL452	Brandy Baldwin	
819	GBC980	2011	Ranger	Comp. P/U	EL452	Sarah Davis	
820	GBC973	2011	Ranger	Comp. P/U	EL452	Jevon Brown	
821	GBC988	2011	F-350	Utility	EN450	Jeff Hindsley	
822	GBC9 57	2012	F-550	Utility	EL451	Shannon Wagner	
824	W396 YD	2012	Escape Hybrid	SUV	MK412	David Richardson	
825	GA1943	2012	M2-106	Bucket	EL451	Al Harris	
826	BMDJ06	2013	Explorer	SUV	GM440	Mark Cutshaw	
827	BMDJ20	2012	F-150	Pickup	EN450	William Grant	
828	BMDJ19	2012	F-150	Pickup	EL451	Rich Crigger	
829	GBC970	2013	F-150	Pickup	EN450	Chris Hebert	
830	T005DR	2013	Fusion	Sedan	CS411	Roger LaCharite	

831	GBF938	2013	F-250	Utility	EN450	Jeff Hindsley	
832	GA9255	2013	M2-106	Bucket	EL451	Spare	
833	GA9256	2014	M2-106	Digger Derrick	EL451	Spare	
834	GBC968	2013	185DPQ	Trailer	EL451	Air Compressor	
155	GBU483	2004	F550	Utility Welder	OP450	NE Gas Ops Spare	
213	GBC953	2010	Express 2500	Van	OP450	NE Gas Ops On-Call	
229	GBF936	2013	F-150	Pickup	OP450	George Speerin	
823	GBC8 83	2012	F-550	Utility	OP450	Dave Pluta	
787	GA4431	2002	4300	Bobtail	PR450	Spare	
793	GBQ063	2005	BC/M2	Bobtail	PR450	James Moore	
797	GBZ814	2006	F550	Utility	PR450	Dave Pluta	
803	GA0302	2008	4300	Bobtail	PR450	Terry Simmons	
805	GBC966	1982		Trailer	PR450	Equipment Trailer	
806	GBC897	2000	HSE16	Trailer	PR450	Equipment Trailer	
807	GBF941	2001	F550	Utility	PR450	On-Call Truck	
815	GBZ807	2006	RF6101	Trailer	PR450	Equipment Trailer	
		2007		Forklift	WH450		
		2012		Forklift	WH450		
		1994		Generator	EL451		
		2001		Excavator	EL452		
		2009		Mower	EL451		
		2006		Generator	PR450		
		2000		Compress	PR450		
		2001		Trencher	PR450		

20. CRITICAL CUSTOMER LIST

A. Hospitals, Clinics, Nursing Homes

Name	Address	Telephone		Contact Person
Baptist Medical Center - Nassau	1700 East Lime St	321-3500 (main)		Wayne Arnold
Amelia Island Care Center	2700 Atlantic Ave	261-5518		Sharon Jamison
		753-3575 Home		
Quality Health	1625 Lime St	261-0771		Steve Jordan
		225-2351 (Answer service)		
Nassau County Health Dept.	30 South 4th St.	548-1860 or 548-1800		Eugina Seidel
Savannah Grand	1900 Amelia Trace Ct.	321-0898	Cell 662-4568	TammiHolland
Home 321-3478				
Osprey Village	76 Osprey Village Dr.	277-3337 x11	Cell 753-2435	Dana Sargent
Jane Adams House	1550 Nectarine St	261-9494	Cell 583-3526	Jeanett Adams

B. Public Utilities – Major Resorts

Name	Address	Telephone		Contact Person
Fernandina Waste Water/Water	1007 South 5th St	277-7380 Ext. 224	753-1412 (cell)	John Mandrick
Nassau Utilities	5390 First Coast Hwy	261-0822	491-7330	Doug Hewett
		261-9452		After Hours
		753-2989 plant		Danny White
Florida Power and Light		(800) 226-3545		
AIP – Security		277-5914	491-4445	Alan Barker
Ritz Carlton		277-1100	753-2122 cell	Tom Gagne
ATT	1910 S. 8th St.	407-2569	(904) 238-8263(cell)	Scott Miller
		727-1544	(904) 403-1894(cell)	Marvin Fisher

C. Major Disaster Shelters/Motels

Name	Address	Telephone	Contact Person
Nassau Holiday	Hwy 17, Yulee	225-2397	
Amelia Hotel	1997 So. Fletcher Ave	261-5735	
Amelia South Condo's	3350 So. Fletcher Ave	261-7991	
Beachside Motel	3172 So. Fletcher Ave	261-4236	
Elizabeth Pointe Lodge	98 So. Fletcher Ave.	277-4851	
Days Inn	2707 Sadler Road	277-2300	
Hardee Elementary	2200 Susan Drive	491-7936	
F. B. High School	435 Citrona Drive	491-7937	
F.B. Middle School	315 Citrona Drive	491-7938	
Southside Elementary	1112 Jasmine St.	491-7941	
Yulee Elementary	86083 Felmore Rd.	225-5192	
Yulee High School	85375 Miner Rd.	225-8641	
Yulee Middle School	85439 Miner Rd.	491-7944	
Yulee Primary	Goodbread Road	491-7945	
Hampton Inn	2549 Sadler Road	321-1111	
Holiday Inn	76071 Sidney Place	849-0200	
Hampton Inn (downtown)	19 South 2nd St	491-4911	
Comfort Suites	2801 Atlantic Ave.	261-0193	

D. Municipal and State Emergency Services

Name	Address	Telephone	Contact Person
Florida Highway Patrol	Jacksonville	695-4115	Keith Gaston
American Red Cross	NE Chapter	358-8091	
Fernandina Police Dept.	Lime St.	277-7342	Dispatcher
Dept. of Transportation	Jacksonville	360.5400	
Chemtrec		1-800-424-9300	
Chlorine Institute		1-703-741-5760	

E. Communication and Broadcasting Services

Name	Address	Telephone	Contact Person
WOKV Radio		245-8866	Rich Jones
	Cell	718-7503	
WQIK Radio		636-0507	
WAPE Radio		245-8500/01	Tim Clarke

F. Major Food Storage/Processing Facilities

Name	Address	Telephone	Contact Person
Publix Super Market	1421 So. 14th St	277-4911	
Winn Dixie Stores	1722 So. 8th St	277-2539	
Hedges Meat Shoppe	Hwy 17 South	225-9709	
Winn Dixie (Yulee)	22 Lofton Sq	261-6100	
Harris Teeter	4800 1st Coast Hwy	491-1213	
Super WalMart	SR 200	261-9410	

G. Correction Facilities

Name	Address	Telephone	Contact Person
Nassau House	1781 Lisa Ave.	277-4244	

H. Airports

Name	Address	Telephone	Contact Person
McGill Aviation Inc.	F.B. Airport	261-7890	Sean McGill

G. News Media

Name	Address	Telephone	Contact Person
Fernandina Newsleader	261-3696	Fax 261-3698	

21. ADDRESS AND TELEPHONE LISTING OF ACTIVE EMPLOYEES

Name	Address	Telephone
Atkins, Mary	111 S. 11th St.	753-3208
Baldwin, Brandy	30970 Paradise Commons unit 316	556-0595
Beale, Susan	86189 Augustus Ave	225-0416
Beverly, Justin	45673 Pickette St, Callahan	370-9596
Blazina, Greg	115 Pineapple Ct., Longwood, Fl	407-339-5649
Boatright, Curtis	768 Wax Wing Lane	261-6988
Bolyard, Renee	96032 Inlet Cove Court	261-2123
Britton, Lynn	Kingsland, Ga	248-252-7370
Brown, Clint	85116 Harts Rd, Yulee	305-2863
Brown, Jevon	86175 Courtney Isle Way #1210, Yulee	572-2132
Calhoun, Rod	1887 White Sands Way	432-8255
Clardy, Bill	97067 Lee Rd. Yulee	261-4269
Crigger, Rich	32402 Sunny Parke Dr	891-0892
Cutshaw, Mark	32547 Willow Parke	491-7107
Davis, Sarah	2137 Oak Ridge Drive	891-8108
Gamble, Linda	96090 Hidden Marsh Lane	277-8682
Goins, Mia	1417 Holly Drive	352-0672
Grant, Bill	1714 Park Ave	491-7898
Harris, Alfonzo	96081 Baker Dr., Yulee	430-6142
Hebert, Chris	23904 Crescent Parke Dr.	277-3444
Hindsley, Jeff	1812 Reatta Ln	261-7952
Kildow, Parrish	2698 Forrest Dr #A8	912-387-6371
LaCharite, Roger	22 Long Point Drive	321-4262
Maxwell, Donnie	411 So. 5th St	583-1536
McDaniel, James	Fernandina Beach, Fl	753-3153
Moen, Tom	1603 Geddes Lane	310-9522
Montgomery, Dean	96681 Chester Rd, Yulee	415-3086
Montgomery, Jody	96132 Blackrock Rd. Yulee	753-0889
Moore, James	812 Parkview Place West	432-8354
Moore, Randy	76276 Dove Rd. Yulee	225-8769
Peacock, Lewis	86309 Yulee Hills Rd, Yulee	572-2186
Pluta, Dave	97158 Castle Ridge Dr. Yulee	321-1343
Puentes, Jorge	86125 Moriches Drive	430-2011
Reed, Roger	2202 High Rigger Ct	261-3160
Richardson, David	83057 St. Mark Drive, Yulee	548-0499
Speerin, George	2651 First Ave	386-785-4506
Simmons, Terry	622 Spanish Way E	261-0321
Taylor, Steve	1621 Highland St.	261-8738
Thornton, Patti	2035 Bridal Rd.	261-8294
Wagner, Shannon	679 Grove Park Cir	748-3076
Williams, Rena	2034 Russell Road	491-6283
Winston, Linda	96075 Starlight Lane, Yulee	583-4210
Zambrano, Leslie	2135 Cumberland Ct.	556-5451

22. Emergency Telephone List

A. Telephone Repair

AT & T	(904) 238-8263	Scott Miller
	(904) 403-1894	Marvin Fisher
Comcast (Cabling & repair)	(904) 626-2400 cell	(Day) Mike Jackson
	1-855-962-8525	(After hours)

B. Cell Phones

IT	(302) 736-7810	Joe Abba

C. Jacksonville Electric Authority 800-683-5542

Dispatcher	(904) 665-4806	
Dispatcher Supervisor	(904) 665-4156	Allen Putnam
Storm Coordinator	(904) 665-7145	Garry Baker
	(904) 665-7110	Ricky Erixton
SOC (System Operation Center)	(904) 665-4806	
SWITCHING ACTIVITY (all)	(904) 277-1478	TURBINE OPERATOR

D. Emergency Management

Nassau County	(904)548-4980	TBD

E. Law Enforcement - 911

Nassau County	225-0331	Sheriff – Bill Leeper
F.B. City	277-7342	City Police Chief – James Hurley

F. Ambulance - 911

G. News Media

WJWB-Channel 17 Jacksonville	641-1700	Fax 642-7201
WJXT-Channel 4 Jacksonville	399-4000	Fax 393-9822
WTLV-Channel 12 Jacksonville	633-8808	Fax 633-8899
WTEV-Channel 47 Jacksonville	564-1599	Fax 642-5665

H. City/County Officials

Nassau County Office	491-7380		
Danny Leeper	(H) 261-8029	430-3868 Cell	County Commissioner
Stacy Johnson	(H) 261-1154	583-2746 Cell	County Commissioner
Walter Boatright	(H) 879-2564	753-0141 Cell	County Commissioner
County Manager)	(W) 491-7380	Ted Selby	
Susan Steger – City Mayor	(W) 277-0788	206-0572 Cell	(H) 261-4372
Michael Czymbor - City Manager	(W) 277-7305	753-4330 Cell	(H) 310-6182
Jason Higginbotham - City Fire Chief		753-4293 Cell	
James Hurley - City Police Chief –	(W) 277-7344	753-4244 Cell	

I. Public Service Commission

Director	(800) 342-3552
Dan Hoppe-Director	(850) 413-6802
Mark Futrell-Director	(850) 413-6692

J. Genarator Repair

See Emergency Assistance List Section 17.

K. FPUC NE Substations

Stepdown	277-1974
JL Terry	277-1973
AIP	277-1975

23. LOGISTICS

Motels:

Amelia Hotel	261-5735	1997 South Fletcher Ave,
Nassau Holiday Motel	225-2397	U.S. 17 South
Amelia South Condo.	261-7991	3350 So. Fletcher Ave.
Elizabeth Point Lodge	277-4851	98 So. Fletcher Ave.
Days Inn	277-2300	2707 Sadler Road
Hampton Inn	321-1111	2630 Sadler Road
Hampton Inn Downtown	491-4911	19 South 2nd Street
Comfort Inn	261-0193	2801 Atlantic Ave.
Country Inn	225-5855	462577 SR 200

Restaurants:

Applebee's	206-4300	2006 South 8th Street
Baxter's	277-4503	4919 1st Coast Hwy
Florida House	491-3322	22 South 3rd Street
Sonny's BBQ	261-6632	2742 So. 8th St.
Barbara Jean's	277-3700	960030 Gateway Blvd.
Huddle House	261-2933	1855 S. 8th St
Murrays Grill	261-2727	SR 200
Chilis	225-8666	SR 200

Food Stores:

Harris Teeter's	491-1213
Publix	277-4911
Winn Dixie	277-2539
Winn Dixie (Yulee)	261-6100
Super WalMart	261-9410

Cellular Phones:
Verizon call Joe Abba IT (302) 736-7810

Water Supply:
Fernandina City of to supply water
Nantze Springs Water Co. 800-239-7873

Ice Supply:
Winn Dixie 277-2539

Service Stations:
Flash Foods Store's 261-6563
Sonoco 277-2384

Vehicle Repair Facilities:
Altec Industries Inc (561) 686-8550 West Palm Beach
Maudlin International (904) 783-9822

Rental Equipment
United Rental (904)757-9393

Cable Davenport Cell# (904)759-8257

Flashlights (20 w/batteries):

Quantity on hand
WalMart (Additional) 261-5306

Portable AM/FM Radios w/batteries:
WalMart 261-5306
Walmart (Yulee) 261-9410

24. SERVICE PLAN TO SUPPLY POWER TO FPU OFFICES

During an emergency it is imperative that power be restored to the office/complexes located at 780 Amelia Island Parkway and 911 South 8th Street as soon as possible. Also of the utmost importance is to ensure the feeder to the building is maintained in optimum working order at all times. This includes tree trimming, replacing deteriorated poles, replacing defective equipment, etc.

After an emergency in which power is lost to the office at 911 S. 8th Street, Operations will dispatch a crew to the Terry Substation in order to determine the status of the OCB# 214. That feeder will also be patrolled to determine what will be needed to restore service to the office. Available personnel will be utilized to restore power.

If required, downstream switches should be opened so that power may be restored to the office as soon as possible.

Situation 1:
Terry Substation energized. Feeder OCB# 214 disabled. Ride line to determine the location of the fault. If extensive, open dead end jumpers as far from the substation as possible to maintain service to the office at 911 S. 8th Street.

Situation 2:
Stepdown Substation energized. Open OCB# 214 at Terry Substation and open OCB# 310 at Stepdown Substation, close pole switch number 780 at Clinch Drive and Bonnieview Road. Close OCB# 310. Feeder OCB# 310 should hold the load, if not, shed some load.
The Operations Center at 780 Amelia Island Pkwy is served from an underground feeder #312 from Stepdown Substation. If power is lost, a gas powered total building generator will provide backup service until the problem is resolved.

25. POST-STORM DATA COLLECTION AND FORENSIC ANALYSIS

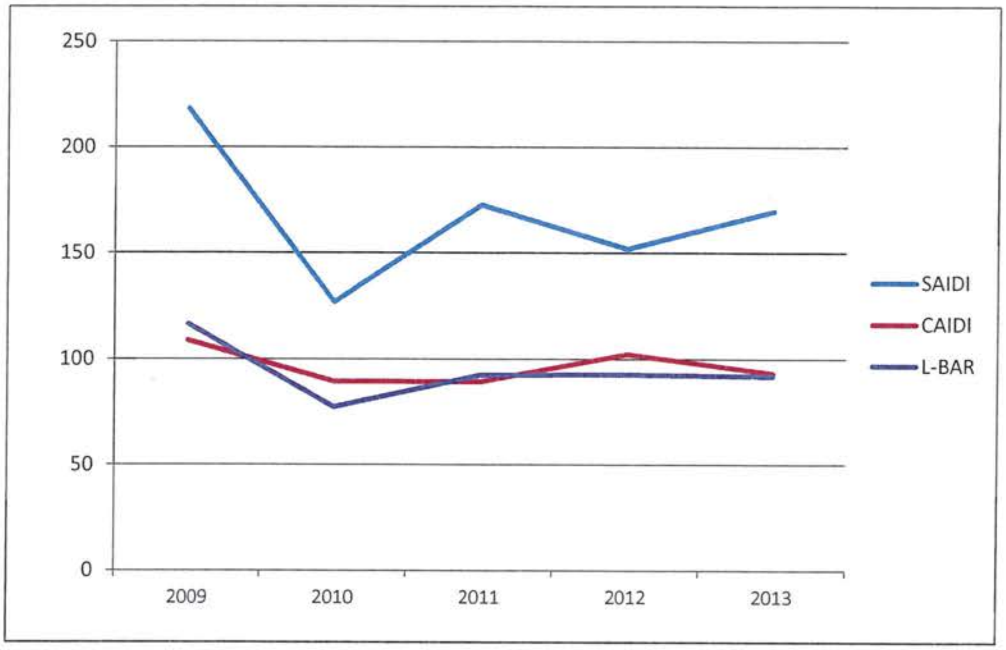
FPUC will employ contractors to perform both the post-storm data collection and forensics analysis should a significant storm occur. The contractors will be provided with system mapping information and requested to collect post-storm damage information on areas as defined by the company. The areas will be selected in order to survey the areas in which the most damage occurs in order to gain the most information.

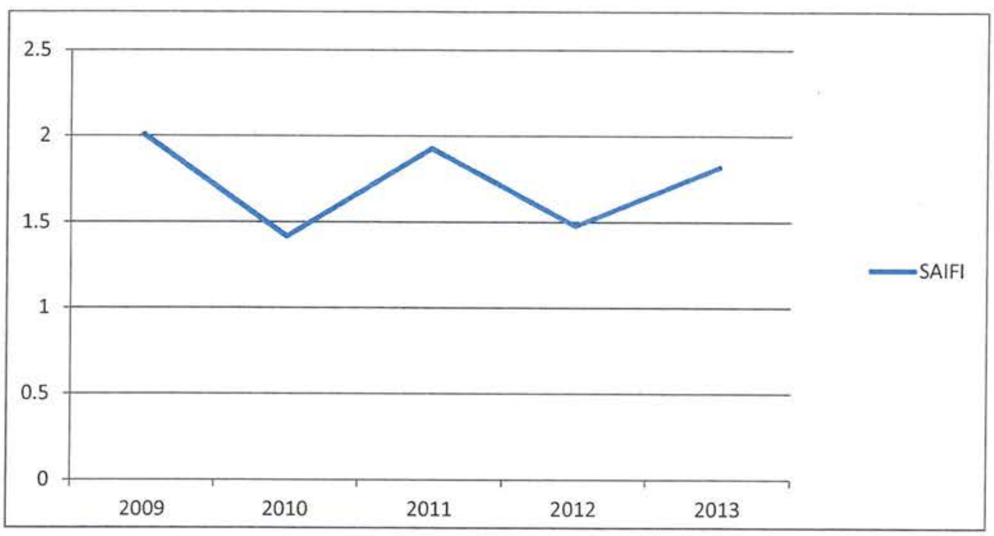
Damage will be identified so that the cause of the outage is identified as it relates to trees, wind, debris, conductor failure, pole failure, etc. which will be identified on the map. Depending upon the degree of damage, forensic analysis may be collected during this process. However, if the damage is extensive the forensics analysis will be performed as soon as possible after the post-storm data collection is completed.

Data collected during the collection process will be analyzed after completion of all storm related work has been completed. This analysis will summarize the type damage and failure modes of outages in order to determine methods to improve reliability in the future.

Florida Public Utilities Reliability Metrics

YEAR	SAIDI	CAIDI	SAIFI	L-BAR
2009	218.4	108.81	2.01	116.74
2010	127.03	89.53	1.42	77.45
2011	172.65	89.39	1.93	92.54
2012	152	102.43	1.48	92.75
2013	169.66	93.31	1.82	91.97





2014 and 2015 Capital Projects

Upgrade the Greenwood to Malone Distribution Feeder	$300,000
Purchase and install an Electronic Recloser	$25,000
Construct the extension of underground feeder #312	$550,000
Replace 34 damaged wood transmission poles with concrete poles	$1,180,000
Replace substation batteries at AIP substation	$25,000
Purchase and install 40 MVA Substation Transformer at JL Terry Sub.	$915,500
Upgrade underground electric system at Gateway to Amelia	$100,000
Upgrade distribution feeder to Hospital in Marianna	$120,000
Install Rayonier Load Bank	$800,000
Relocate and upgrade Rayonier 69 KV Transmission Line	$1,600,000
Construct substation at Rayonier	$1,400,000
Purchase 2,500 KW Mobile Generator	$1,000,000
Decayed Pole Replacements	$1,130,000
Total	$9,145,500

Exhibit MC/DS-6

Docket 140025-EI

Florida Public Utilities

Year End Update Safety Statistics

Preventable Accidents/Incidents – 10 Total as of 12/31/13 (2012 – 22, 2011 – 27)

- Vehicle – 6
- Injury – 2
- General Liability – 2

Vehicle Incidents – 31 (Includes Cracked Windshields and Mirrors)

- Reportable – 12
- Preventable – 6
- Number of Miles Driven – 4,047,505
- Accident Rate – 2.96478942

Year	Vehicle Incidents	Reportable Accidents	Preventable Accidents	Miles Driven	Accident Rate
2011	35	14	11	3,504,339	3.995047282
2012	32	14	14	3,714,671	3.768839825
2013	31	12	6	4,047,505	2.96478942

OSHA Recordable Injuries 12/31/13

- Recordable – 5
- Incident Rate – 1.699848763
- DART Rate – 1.019909258
- DART Severity Rate – 15.97857837
- Hours Worked - 588,287

Year	OSHA Recordable	Incident Rate	DART Rate	DART Severity Rate	Hours Worked
2010	33	10.0844	3.9726	65.3964	645,470
2011	19	6.5609	3.4458	34.9039	578,536
2012	16	5.7838	3.2534	61.4528	553,269
2013	5	1.6998	1.0199	15.9785	588,287

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
Consolidated Electric Division
DOCKET NO.: 140025-EI

Summary of all proposed changes in rates and rate classes, detailing current and proposed classes of outdoor lighting services

Exhibit MC/DS-7

Witness: Mark Cutshaw

Northeast Florida

Type of Facility	Est. Monthly KWH	Present Rates - Outdoor Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Proposed Rates - Outdoor Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Base Percent Increase	Total Percent Increase
100w HPS Cobra Head-OL	41	$6.10	$1.58	$0.96	$8.64	$2.14	$10.78	$6.34	$1.83	$1.88	$10.05	$2.14	$12.19	16.3%	13.1%
175w MV Cobra Head -OL	72	$1.44	$2.72	$0.52	$4.68	$3.76	$8.44	$1.19	$3.15	$1.04	$5.38	$3.76	$9.14	15.0%	8.3%
400w MV Cobra Head-OL	154	$4.39	$5.82	$0.89	$11.10	$8.05	$19.15	$1.31	$6.74	$1.12	$9.17	$8.05	$17.22	-17.4%	-10.1%
1000w HPS Flood -OL2	405	$16.38	$15.61	$2.19	$34.18	$21.17	$55.35	$18.99	$18.09	$2.54	$39.62	$21.17	$60.79	15.9%	9.8%
1000w MH Flood - OL2	405	$15.20	$15.61	$2.03	$32.84	$21.17	$54.01	$17.51	$18.09	$2.48	$38.08	$21.17	$59.25	16.0%	9.7%
1000w MH Vert Shoebox - OL2	405	$21.31	$15.61	$2.69	$39.61	$21.17	$60.78	$24.70	$18.09	$3.12	$45.91	$21.17	$67.08	15.9%	10.4%
100w HPS Amer Rev-OL2	41	$8.10	$1.58	$1.15	$10.83	$2.14	$12.97	$8.23	$1.83	$2.78	$12.84	$2.14	$14.98	18.6%	15.5%
100w HPS Cobra Head-OL2	41	$6.10	$1.58	$0.96	$8.64	$2.14	$10.78	$6.34	$1.83	$1.88	$10.05	$2.14	$12.19	16.3%	13.1%
100w HPS SP2 Spectra -OL2	41	$18.18	$1.58	$3.16	$22.92	$2.14	$25.06	$21.07	$1.83	$3.66	$26.56	$2.14	$28.70	15.9%	14.5%
100w MH SP2 Spectra -OL2	41	$18.04	$1.58	$2.20	$21.82	$2.14	$23.96	$20.91	$1.83	$2.55	$25.29	$2.14	$27.43	15.9%	14.5%
150w HPS Acorn-OL2	61	$14.42	$2.34	$1.83	$18.59	$3.19	$21.78	$16.72	$2.71	$2.12	$21.55	$3.19	$24.74	15.9%	13.6%
150w HPS ALN 440 -OL2	61	$21.46	$2.34	$2.34	$26.14	$3.19	$29.33	$24.88	$2.71	$3.03	$30.62	$3.19	$33.81	17.1%	15.3%
150w HPS Am Rev-OL2	61	$8.31	$2.34	$1.14	$11.79	$3.19	$14.98	$7.70	$2.71	$3.79	$14.20	$3.19	$17.39	20.4%	16.1%
175w MH ALN 440 -OL2	71	$21.60	$2.75	$2.66	$27.01	$3.71	$30.72	$25.73	$3.19	$2.22	$31.14	$3.71	$34.85	15.3%	13.4%
175w MH Shoebox -OL2	71	$16.62	$2.75	$2.15	$21.52	$3.71	$25.23	$19.27	$3.19	$2.49	$24.95	$3.71	$28.66	15.9%	13.6%
200w HPS Cobra Head -OL2	81	$9.32	$3.13	$0.42	$12.87	$4.23	$17.10	$8.31	$3.63	$2.14	$14.08	$4.23	$18.31	9.4%	7.1%
250w HPS Cobra Head -OL2	101	$11.21	$3.88	$1.46	$16.55	$5.28	$21.83	$9.07	$4.50	$3.36	$16.93	$5.28	$22.21	2.3%	1.7%
250w HPS Flood -OL2	101	$8.49	$3.88	$1.34	$13.71	$5.28	$18.99	$9.98	$4.50	$2.05	$16.53	$5.28	$21.81	20.6%	14.8%
250w MH Shoebox-OL2	101	$17.69	$3.88	$2.40	$23.97	$5.28	$29.25	$20.51	$4.50	$2.78	$27.79	$5.28	$33.07	15.9%	13.1%
400w HPS Cobra Head -OL2	162	$8.43	$6.26	$1.34	$16.03	$8.47	$24.50	$9.21	$7.26	$2.35	$18.82	$8.47	$27.29	17.4%	11.4%
400w HPS Flood - OL2	162	$13.08	$6.26	$1.66	$21.00	$8.47	$29.47	$15.16	$7.26	$1.92	$24.34	$8.47	$32.81	15.9%	11.3%
400w MH Flood OL2	162	$8.81	$6.26	$1.39	$16.46	$8.47	$24.93	$10.29	$7.26	$1.88	$19.43	$8.47	$27.90	18.0%	11.9%
10' Alum Deco Base-OL2		$13.50			$13.50		$13.50	$15.77			$15.77		$15.77	16.8%	16.8%
13' Decorative Concrete-OL2		$10.36			$10.36		$10.36	$12.01			$12.01		$12.01	15.9%	15.9%
18' Fiberglass Round-OL2		$6.86			$6.86		$6.86	$8.48			$8.48		$8.48	23.6%	23.6%
20' Decorative Concrete-OL2		$11.75			$11.75		$11.75	$13.59			$13.59		$13.59	15.7%	15.7%
30' Wood Pole Std-OL2		$3.95			$3.95		$3.95	$4.55			$4.55		$4.55	15.2%	15.2%
35' Concrete Square-OL2		$11.45			$11.45		$11.45	$13.44			$13.44		$13.44	17.4%	17.4%
40' Wood Pole Std - OL2		$7.85			$7.85		$7.85	$9.10			$9.10		$9.10	15.9%	15.9%
30' Wood pole		$3.53			$3.53		$3.53	$4.09			$4.09		$4.09	15.9%	15.9%

Purchased Power Adjustment	$0.05218
Conservation	$0.00010

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
Consolidated Electric Division
DOCKET NO.: 140025-EI

Summary of all proposed changes in rates and rate classes, detailing current and proposed classes of outdoor lighting services

Exhibit MC/DS-7

Witness: Mark Cutshaw

Northwest Florida

Type of Facility	Est. Monthly KWH	Present Rates - Outdoor Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Proposed Rates - Outdoor Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Base Percent Increase	Total Percent Increase
100w HPS Cobra Head-OL	41	$6.10	$1.58	$0.96	$8.64	$3.12	$11.76	$6.34	$1.83	$1.88	$10.05	$3.12	$13.17	16.3%	12.0%
175w MV Cobra Head -OL	72	$1.44	$2.72	$0.52	$4.68	$5.48	$10.16	$1.19	$3.15	$1.04	$5.38	$5.48	$10.86	15.0%	6.9%
400w MV Cobra Head-OL	154	$4.39	$5.82	$0.89	$11.10	$11.72	$22.82	$1.31	$6.74	$1.12	$9.17	$11.72	$20.89	-17.4%	-8.5%
1000w HPS Flood -OL2	405	$16.38	$15.61	$2.19	$34.18	$30.82	$65.00	$18.99	$18.09	$2.54	$39.62	$30.82	$70.44	15.9%	8.4%
1000w MH Flood - OL2	405	$15.20	$15.61	$2.03	$32.84	$30.82	$63.66	$17.51	$18.09	$2.48	$38.08	$30.82	$68.90	16.0%	8.2%
1000w MH Vert Shoebox - OL2	405	$21.31	$15.61	$2.69	$39.61	$30.82	$70.43	$24.70	$18.09	$3.12	$45.91	$30.82	$76.73	15.9%	8.9%
100w HPS Amer Rev-OL2	41	$8.10	$1.58	$1.15	$10.83	$3.12	$13.95	$8.23	$1.83	$2.78	$12.84	$3.12	$15.96	18.6%	14.4%
100w HPS Cobra Head-OL2	41	$6.10	$1.58	$0.96	$8.64	$3.12	$11.76	$6.34	$1.83	$1.88	$10.05	$3.12	$13.17	16.3%	12.0%
100w HPS SP2 Spectra -OL2	41	$18.18	$1.58	$3.16	$22.92	$3.12	$26.04	$21.07	$1.83	$3.66	$26.56	$3.12	$29.68	15.9%	14.0%
100w MH SP2 Spectra -OL2	41	$18.04	$1.58	$2.20	$21.82	$3.12	$24.94	$20.91	$1.83	$2.55	$25.29	$3.12	$28.41	15.9%	13.9%
150w HPS Acorn-OL2	61	$14.42	$2.34	$1.83	$18.59	$4.64	$23.23	$16.72	$2.71	$2.12	$21.55	$4.64	$26.19	15.9%	12.7%
150w HPS ALN 440 -OL2	61	$21.46	$2.34	$2.34	$26.14	$4.64	$30.78	$24.88	$2.71	$3.03	$30.62	$4.64	$35.26	17.1%	14.6%
150w HPS Am Rev-OL2	61	$8.31	$2.34	$1.14	$11.79	$4.64	$16.43	$7.70	$2.71	$3.79	$14.20	$4.64	$18.84	20.4%	14.7%
175w MH ALN 440 -OL2	71	$21.60	$2.75	$2.66	$27.01	$5.40	$32.41	$25.73	$3.19	$2.22	$31.14	$5.40	$36.54	15.3%	12.7%
175w MH Shoebox -OL2	71	$16.62	$2.75	$2.15	$21.52	$5.40	$26.92	$19.27	$3.19	$2.49	$24.95	$5.40	$30.35	15.9%	12.7%
200w HPS Cobra Head -OL2	81	$9.32	$3.13	$0.42	$12.87	$6.16	$19.03	$8.31	$3.63	$2.14	$14.08	$6.16	$20.24	9.4%	6.4%
250w HPS Cobra Head -OL2	101	$11.21	$3.88	$1.46	$16.55	$7.69	$24.24	$9.07	$4.50	$3.36	$16.93	$7.69	$24.62	2.3%	1.6%
250w HPS Flood -OL2	101	$8.49	$3.88	$1.34	$13.71	$7.69	$21.40	$9.98	$4.50	$2.05	$16.53	$7.69	$24.22	20.6%	13.2%
250w MH Shoebox-OL2	101	$17.69	$3.88	$2.40	$23.97	$7.69	$31.66	$20.51	$4.50	$2.78	$27.79	$7.69	$35.48	15.9%	12.1%
400w HPS Cobra Head -OL2	162	$8.43	$6.26	$1.34	$16.03	$12.33	$28.36	$9.21	$7.26	$2.35	$18.82	$12.33	$31.15	17.4%	9.8%
400w HPS Flood - OL2	162	$13.08	$6.26	$1.66	$21.00	$12.33	$33.33	$15.16	$7.26	$1.92	$24.34	$12.33	$36.67	15.9%	10.0%
400w MH Flood OL2	162	$8.81	$6.26	$1.39	$16.46	$12.33	$28.79	$10.29	$7.26	$1.88	$19.43	$12.33	$31.76	18.0%	10.3%
10' Alum Deco Base-OL2		$13.50			$13.50		$13.50	$15.77			$15.77		$15.77	16.8%	16.8%
13' Decorative Concrete-OL2		$10.36			$10.36		$10.36	$12.01			$12.01		$12.01	15.9%	15.9%
18' Fiberglass Round-OL2		$6.86			$6.86		$6.86	$8.48			$8.48		$8.48	23.6%	23.6%
20' Decorative Concrete-OL2		$11.75			$11.75		$11.75	$13.59			$13.59		$13.59	15.7%	15.7%
30' Wood Pole Std-OL2		$3.95			$3.95		$3.95	$4.55			$4.55		$4.55	15.2%	15.2%
35' Concrete Square-OL2		$11.45			$11.45		$11.45	$13.44			$13.44		$13.44	17.4%	17.4%
40' Wood Pole Std - OL2		$7.85			$7.85		$7.85	$9.10			$9.10		$9.10	15.9%	15.9%
30' Wood pole		$3.53			$3.53		$3.53	$4.09			$4.09		$4.09	15.9%	15.9%

Purchased Power Adjustment	$0.07600
Conservation	$0.00010

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
Consolidated Electric Division
DOCKET NO.: 140025-EI

Summary of all proposed changes in rates and rate classes, detailing current and proposed classes of street lighting services

Exhibit MC/DS-7

Witness: Mark Cutshaw

Northeast Florida

Type of Facility	Est. Monthly KWH	Present Rates - Street Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Proposed Rates - Street Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Base Percent Increase	Total Percent Increase
175w MV Cobra Head - SL1-2	72	$0.67	$2.71	$1.23	$8.64	$3.76	$8.37	$1.19	$3.15	$1.04	$10.05	$3.76	$9.14	16.3%	9.2%
400w MV Cobra Head - SL1-3	154	$1.13	$5.81	$1.40	$4.68	$8.05	$16.39	$1.31	$6.74	$1.12	$5.38	$8.05	$17.22	15.0%	5.1%
175w MV Cobra Head -SL2	72	$0.67	$2.71	$1.23	$11.10	$3.76	$8.37	$1.19	$3.15	$1.04	$9.17	$3.76	$9.14	-17.4%	9.2%
400w MV Cobra Head -SL2	154	$1.13	$5.81	$1.40	$34.18	$8.05	$16.39	$1.31	$6.74	$1.12	$39.62	$8.05	$17.22	15.9%	5.1%
1000w MH Flood -SL3	405	$11.09	$15.61	$6.79	$32.84	$21.17	$54.66	$17.51	$18.09	$2.48	$38.08	$21.17	$59.25	16.0%	8.4%
100w HPS Amer -SL3	41	$5.99	$1.58	$3.80	$39.61	$2.14	$13.51	$8.23	$1.83	$2.78	$45.91	$2.14	$14.98	15.9%	10.9%
100w HPS Cobra Head- SL3	41	$4.37	$1.58	$2.78	$10.83	$2.14	$10.87	$6.34	$1.83	$1.88	$12.84	$2.14	$12.19	18.6%	12.1%
150w HPS Acorn -SL3	61	$10.47	$2.34	$6.15	$8.64	$3.19	$22.15	$16.72	$2.71	$2.12	$10.05	$3.19	$24.74	16.3%	11.7%
150w HPS Amer Rev -SL3	61	$5.85	$2.34	$4.28	$22.92	$3.19	$15.66	$7.70	$2.71	$3.79	$26.56	$3.19	$17.39	15.9%	11.0%
175w MH ALN 440 -SL3	71	$22.36	$2.75	$1.71	$21.82	$3.71	$30.53	$25.73	$3.19	$2.22	$25.29	$3.71	$34.85	15.9%	14.2%
200w HPS Cobra Head -SL3	81	$5.61	$3.13	$2.88	$18.59	$4.23	$15.85	$8.31	$3.63	$2.14	$21.55	$4.23	$18.31	15.9%	15.5%
250w HPS Cobra Head -SL3	101	$5.38	$3.88	$3.94	$26.14	$5.28	$18.48	$9.07	$4.50	$3.36	$30.62	$5.28	$22.21	17.1%	20.2%
250w HPS Flood - SL3	101	$9.22	$3.88	$5.38	$11.79	$5.28	$23.76	$9.98	$4.50	$2.05	$14.20	$5.28	$21.81	20.4%	-8.2%
400w HPS Cobra Head -SL3	162	$6.28	$6.26	$4.41	$27.01	$8.47	$25.42	$9.21	$7.26	$2.35	$31.14	$8.47	$27.29	15.3%	7.4%
400w MH Flood -SL3	162	$9.63	$6.26	$11.58	$21.52	$8.47	$35.94	$10.29	$7.26	$1.88	$24.95	$8.47	$27.90	15.9%	-22.4%
10' Alum Deco Base-SL3		$14.92			$14.92		$14.92	$15.77			$15.77		$15.77	5.7%	5.7%
13' Deco Concrete - SL3		$10.35			$10.35		$10.35	$12.01			$12.01		$12.01	16.0%	16.0%
18' Fiberglass Round-SL3		$7.64			$7.64		$7.64	$8.48			$8.48		$8.48	11.0%	11.0%
20' Decorative Concrete-SL3		$11.45			$11.45		$11.45	$13.59			$13.59		$13.59	18.7%	18.7%
30' Wood Pole Std - SL3		$3.67			$3.67		$3.67	$4.55			$4.55		$4.55	24.0%	24.0%
35' Concrete Square-SL3		$12.81			$12.81		$12.81	$13.44			$13.44		$13.44	4.9%	4.9%

Purchased Power Adjustment	$0.05218
Conservation	$0.00010

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
Consolidated Electric Division
DOCKET NO.: 140025-EI

Summary of all proposed changes in rates and rate classes, detailing current and proposed classes of street lighting services

Witness: Mark Cutshaw

Northwest Florida

Type of Facility	Est. Monthly KWH	Present Rates - Street Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Proposed Rates - Street Lighting: Facility Charge	Energy Charge	Maint. Charge	Base Monthly Charge	Fuel Conserv. Charge	Total Monthly Charge	Base Percent Increase	Total Percent Increase
175w MV Cobra Head - SL1-2	72	$0.67	$2.71	$1.23	$8.64	$3.76	$8.37	$1.19	$3.15	$1.04	$10.05	$3.76	$9.14	16.3%	9.2%
400w MV Cobra Head - SL1-3	154	$1.13	$5.81	$1.40	$4.68	$8.05	$16.39	$1.31	$6.74	$1.12	$5.38	$8.05	$17.22	15.0%	5.1%
175w MV Cobra Head -SL2	72	$0.67	$2.71	$1.23	$11.10	$3.76	$8.37	$1.19	$3.15	$1.04	$9.17	$3.76	$9.14	-17.4%	9.2%
400w MV Cobra Head -SL2	154	$1.13	$5.81	$1.40	$34.18	$8.05	$16.39	$1.31	$6.74	$1.12	$39.62	$8.05	$17.22	15.9%	5.1%
1000w MH Flood -SL3	405	$11.09	$15.61	$6.79	$32.84	$21.17	$54.66	$17.51	$18.09	$2.48	$38.08	$21.17	$59.25	16.0%	8.4%
100w HPS Amer -SL3	41	$5.99	$1.58	$3.80	$39.61	$2.14	$13.51	$8.23	$1.83	$2.78	$45.91	$2.14	$14.98	15.9%	10.9%
100w HPS Cobra Head- SL3	41	$4.37	$1.58	$2.78	$10.83	$2.14	$10.87	$6.34	$1.83	$1.88	$12.84	$2.14	$12.19	18.6%	12.1%
150w HPS Acorn -SL3	61	$10.47	$2.34	$6.15	$8.64	$3.19	$22.15	$16.72	$2.71	$2.12	$10.05	$3.19	$24.74	16.3%	11.7%
150w HPS Amer Rev -SL3	61	$5.85	$2.34	$4.28	$22.92	$3.19	$15.66	$7.70	$2.71	$3.79	$26.56	$3.19	$17.39	15.9%	11.0%
175w MH ALN 440 -SL3	71	$22.36	$2.75	$1.71	$21.82	$3.71	$30.53	$25.73	$3.19	$2.22	$25.29	$3.71	$34.85	15.9%	14.2%
200w HPS Cobra Head -SL3	81	$5.61	$3.13	$2.88	$18.59	$4.23	$15.85	$8.31	$3.63	$2.14	$21.55	$4.23	$18.31	15.9%	15.5%
250w HPS Cobra Head -SL3	101	$5.38	$3.88	$3.94	$26.14	$5.28	$18.48	$9.07	$4.50	$3.36	$30.62	$5.28	$22.21	17.1%	20.2%
250w HPS Flood - SL3	101	$9.22	$3.88	$5.38	$11.79	$5.28	$23.76	$9.98	$4.50	$2.05	$14.20	$5.28	$21.81	20.4%	-8.2%
400w HPS Cobra Head -SL3	162	$6.28	$6.26	$4.41	$27.01	$8.47	$25.42	$9.21	$7.26	$2.35	$31.14	$8.47	$27.29	15.3%	7.4%
400w MH Flood -SL3	162	$9.63	$6.26	$11.58	$21.52	$8.47	$35.94	$10.29	$7.26	$1.88	$24.95	$8.47	$27.90	15.9%	-22.4%
10' Alum Deco Base-SL3		$14.92			$14.92		$14.92	$15.77			$15.77		$15.77	5.7%	5.7%
13' Deco Concrete - SL3		$10.35			$10.35		$10.35	$12.01			$12.01		$12.01	16.0%	16.0%
18' Fiberglass Round-SL3		$7.64			$7.64		$7.64	$8.48			$8.48		$8.48	11.0%	11.0%
20' Decorative Concrete-SL3		$11.45			$11.45		$11.45	$13.59			$13.59		$13.59	18.7%	18.7%
30' Wood Pole Std - SL3		$3.67			$3.67		$3.67	$4.55			$4.55		$4.55	24.0%	24.0%
35' Concrete Square-SL3		$12.81			$12.81		$12.81	$13.44			$13.44		$13.44	4.9%	4.9%

Purchased Power Adjustment	$0.05218
Conservation	$0.00010

FLORIDA PUBLIC UTILITIES
COMPUTATION OF COMBINED LIGHT FUEL RATES
2014 PROJECTIONS

Exhibit MC/DS-8

Docket 140025-EI

NORTHWEST FLORIDA DIVISION			JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	TOTAL
KWH															
Outdoor Lights	OL,OL-2		380,000	380,000	379,000	380,000	381,000	380,000	383,000	380,000	377,000	377,000	378,000	379,000	4,554,000
Street Lights	SL-1,SL-2,SL-3		95,000	96,000	95,000	96,000	95,000	95,000	95,000	95,000	95,000	94,000	96,000	95,000	1,142,000
			475,000	476,000	474,000	476,000	476,000	475,000	478,000	475,000	472,000	471,000	474,000	474,000	5,696,000
FUEL REVENUES															
Outside Lighting	OL,OL-2	0.07590	28,842	28,842	28,766	28,842	28,918	28,842	29,070	28,842	28,614	28,614	28,690	28,766	345,648
Street Lighting	SL-1,SL-2,SL-3	0.07611	7,230	7,307	7,230	7,307	7,230	7,230	7,230	7,230	7,230	7,154	7,307	7,230	86,915
			36,072	36,149	35,996	36,149	36,148	36,072	36,300	36,072	35,844	35,768	35,997	35,996	432,563
Combined Rate			0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594	0.07594
Including Tax Factor															0.07600

NORTHEAST FLORIDA DIVISION			JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	TOTAL
KWH															
Outdoor Lights	OL,OL-2		102,000	102,000	102,000	102,000	100,000	103,000	104,000	103,000	99,000	97,000	102,000	106,000	1,222,000
Street Lights	SL-1,SL-2,SL-3		81,000	81,000	81,000	81,000	81,000	79,000	81,000	81,000	82,000	81,000	81,000	81,000	971,000
			183,000	183,000	183,000	183,000	181,000	182,000	185,000	184,000	181,000	178,000	183,000	187,000	2,193,000
FUEL REVENUES															
Outside Lighting	OL,OL-2	0.05224	5,328	5,328	5,328	5,328	5,224	5,381	5,433	5,381	5,172	5,067	5,328	5,537	63,835
Street Lighting	SL-1,SL-2,SL-3	0.05202	4,214	4,214	4,214	4,214	4,214	4,110	4,214	4,214	4,266	4,214	4,214	4,214	50,516
			9,542	9,542	9,542	9,542	9,438	9,491	9,647	9,595	9,438	9,281	9,542	9,751	114,351
Combined Rate			0.05214	0.05214	0.05214	0.05214	0.05214	0.05215	0.05215	0.05215	0.05214	0.05214	0.05214	0.05214	0.05214
Including Tax Factor															0.05218

[redacted]

[redacted]

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FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS

OF

OF MATTHEW M. KIM

Q. Please state your name, occupation and business address.

A. My name is Matthew M. Kim. I serve as Vice President and Corporate Controller of Chesapeake Utilities Corporation ("Chesapeake"), which is the parent company of Florida Public Utilities Company ("FPU"). My business address is 909 Silver Lake Boulevard, Dover, Delaware.

Q. Please describe your educational background and professional experience.

A. I graduated with a Bachelor of Science degree in Business Administration with a major in Accounting from Georgetown University in Washington, DC in 1998. I am a Certified Public Accountant, licensed in the District of Columbia. I have 16 years of professional accounting experience. I joined Chesapeake in 2009 as Corporate Controller and was appointed as Assistant Vice President and Vice President by Chesapeake's Board of Directors in 2010 and 2012, respectively. Prior to joining Chesapeake, I was Vice President and Assistant Controller at The Carlyle Group, a global private equity firm, from 2005 to 2009. I also held various positions with public accounting firms for over seven years, from Staff Auditor to Senior Manager. Prior to leaving public accounting in 2005, I was a Senior Manager with PricewaterhouseCoopers LLC.

Q. Please describe your current responsibilities.

A. As Vice President and Corporate Controller, I am responsible for accounting, financial reporting and tax compliance functions within Chesapeake and all of its subsidiaries. This includes daily oversight, management, compliance and policy. I am also involved in the financial planning and budgeting functions within Chesapeake.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. In 2012, I provided testimony before the Florida Public Service Commission (the "Commission") in Docket Number 120311-GU, which was FPU's petition for approval of the acquisition adjustment for its Indiantown division. In 2010, I also provided testimony before the Commission in Docket Number 110133-GU, which was FPU's petition for approval of the acquisition adjustment related to Chesapeake's acquisition of FPU.

Q. Have you previously provided testimony before other regulatory bodies?

A. Yes, in 2010, I provided testimony before the Federal Energy Regulatory Commission ("FERC") in Docket Number RP11-1670.

Q. What is the purpose of your testimony?

A. I am supporting certain schedules of historical data and projected data represented in the MFRs listed in my Exhibit MK-1. Specifically, I will address administrative and general ("A&G") expenses and the allocation of corporate costs included in A&G expenses, as well as some of the management, expense allocation, and accounting changes that have been implemented since FPU was acquired by Chesapeake, along with the benefits tied to those changes. I will also address income taxes, expenses associated with pension and other postretirement benefit plans, as well as Chesapeake's capital structure and financing plans as they relate to FPU.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. Exhibit MK-1 was prepared under my supervision and direction.

Q. Are you sponsoring any MFRs in this case?

A. I am supporting the MFRs listed in Exhibit MK-1. To the best of my knowledge, these MFRs are true and correct.

<u>A&G expenses</u>

Q. Please describe what is included in A&G expenses.

A. A&G expenses include payroll, benefits, outside services and other related costs associated with key administrative functions, including accounting and finance, human resources, communications, information technology ("IT"), corporate governance, and management functions. A&G expenses also include costs associated with various administrative facilities, insurance and expenses associated with FPU's pension and other postretirement benefit plans.

Q. Generally, please explain the accounting of A&G costs?

A. The merger with Chesapeake in 2009 changed the way A&G expenses are recorded for FPU, as well as the type of A&G costs being recorded by FPU. Prior to the merger, all of the A&G expenses were incurred by FPU and allocated within different businesses of FPU (mainly FPU's natural gas operation, FPU's electric operation and FPU's unregulated subsidiary). Subsequent to the merger, certain A&G functions remained in Florida and have continued to be performed by the management and employees dedicated to the Florida businesses, which include FPU and other Florida businesses of Chesapeake (mainly the Florida division of Chesapeake – d.b.a. Central Florida Gas). A&G expenses associated with the functions performed by the Florida management and employees dedicated to serve the Florida businesses are allocated among the Florida businesses only. Other A&G functions have been combined with or transferred to Chesapeake's corporate office for increased quality and efficiency. As a result, FPU is allocated a portion of A&G expenses incurred by Chesapeake's corporate office. The calculation of allocations to FPU is explained in greater detail below. However, generally, the accounting and finance, IT, human resources, corporate governance and certain management functions are some of the examples of the A&G functions now being performed by Chesapeake's corporate office in support of FPU's operations.

Q. What benefits are derived by FPU and its customers from Chesapeake's service of these functions post-merger?

A. This is discussed in much greater detail below but generally speaking, since the merger, FPU has benefited from certain functions and services provided by Chesapeake's corporate office, which were not previously available to FPU on its own. These new functions and services, which include communications, certain business development and expanded management support functions, have increased

FPU's quality of service by enhancing customer engagement, obtaining more accurate and relevant business and market information and providing reliable and efficient service to its customers. These resources and capabilities also enabled FPU to address newly emerging, complex business issues, such as the franchise dispute in Marianna and developing alternative electric fuel supply options. All of these functions and capabilities have increased FPU's customer satisfaction. With the help of Chesapeake's corporate office, FPU has also been able to address expanded business and compliance needs for IT infrastructure and security, accuracy in accounting and financial data, adoption of new regulations by the federal and state governments, and employee training and retention. All of these efficiencies have enabled FPU to continue its outstanding service to its customers and benefit from increased access to capital to maintain and improve its electric system.

Q. How are A&G expenses allocated to FPU?

A. A&G expenses are recorded by FPU in one of the following ways: (a) direct assignment of costs and (b) cost settlement designed to allocate the cost of shared functions and services to business units receiving the benefit of such functions and services. Whenever it is possible and practical, A&G expenses are directly assigned to the business unit incurring such cost. An example of direct assignment of A&G costs is an external audit fee associated with auditing FPU electric operation's annual report on FERC Form No. 1 filed with the Commission. This portion of the annual external audit fee is assigned and recorded directly to FPU. A&G expenses that cannot be directly assigned are allocated among Chesapeake's business units that receive a benefit from such functions and services. Chesapeake utilizes various methodologies in allocation of costs, depending on the type of expense. These methodologies are designed to reflect the relative size and benefit of each business unit receiving shared functions and services and may include direct payroll, profitability, adjusted gross plant, investment and/or the specific level of effort or focus, among others, in determining the allocation basis. Chesapeake utilizes a consistent methodology among all of its business units in allocating the same type of expense. Chesapeake reviews and updates the allocation basis at least annually at the beginning of each fiscal year. A&G expenses incurred by the Florida management and employees dedicated to serve the Florida businesses are allocated among only the Florida businesses. A&G expenses incurred by Chesapeake's corporate office are allocated among all of Chesapeake's businesses receiving benefits from such services.

Q. Please explain further how A&G expenses incurred by Chesapeake's corporate office are allocated.

A. Each of Chesapeake's corporate department has its specific allocation method, which is design to reflect the benefit of service provided by that department to all the business units receiving such service. Generally, Chesapeake's corporate departments use one of the following three allocation methods: task-based, Distrigas formula and investment-based. The first method is the task-based allocation, which identifies department's functions and assigns for each function the level of effort or focus to each business unit receiving its service. Chesapeake utilizes the task-based method to allocate the costs associated with the accounting and finance departments, management and specific IT systems. Based on the specific nature of these services, the task-based allocation method provides the most reasonable reflection of the benefit received by each business unit. The second method is the Distrigas formula, which is a FERC-approved formula attempting to weight various aspects of each of the business units to calculate the appropriate allocation. This formula incorporates three equally-weighted factors: gross plant, net operating revenues (operating income before interest and income taxes) and labor cost. Costs related to IT network, data and desktop maintenance and support, human resources and communications are allocated using the Distrigas formula. Due to the pervasive nature of these services, the Distrigas formula provides the most appropriate basis to allocate these costs. The third method is the investment-based allocation, which uses the level of Chesapeake's investment in each business unit to allocate costs. Costs associated with corporate governance, Chesapeake's Board of Directors and business development, all of which are closely related to the level of investment, are allocated using the investment-based method.

Q. How does Chesapeake ensure a fair distribution of its corporate costs to all of its business units, including unregulated businesses?

A. Chesapeake reviews and updates the allocation basis at least annually or when a significant change occurs to Chesapeake's overall business or corporate functions. Every business unit benefiting from a particular department is allocated a portion of the cost associated with that department, using a consistent methodology.

Chesapeake also reviews the relative size of each business unit, measured by investment, operating income, gross plant and payroll expenses, and compares it to the overall corporate cost being allocated to that business unit to assess the reasonableness of the allocation.

Q. What is FPU's A&G expense budget for the 2015 test year?

A. The projected A&G expense of FPU's electric operation in the 2015 test year is \$5,563,777. Included in this projected A&G expense is \$3,061,986 of A&G expense allocated from Chesapeake's corporate office.

Q. How does this amount compare with the A&G benchmark that the Florida Commission has historically used?

A. The test year benchmark for A&G expenses is \$4,223,626, which was calculated based on the base year (2008) expenses of \$3,720,601 and the compound multiplier of 1.1352. The projected A&G expenses in the 2015 test year are higher than the test year benchmark by approximately \$1.3 million.

Q. Are these costs, including the costs allocated from corporate A&G, a legitimate and necessary cost to FPU of providing service to its customers?

A. Yes. A&G expenses for the 2015 test year include only the A&G costs that are projected to be incurred in supporting FPU's electric operation. The overall A&G costs in the 2015 test year are projected based on historic costs, recent trends and additional costs associated with increased business needs, which are necessary to continue providing outstanding service to FPU's customers. We monitor periodically FPU's A&G costs by comparing them on a per-customer-basis to other investor-owned electric utilities in Florida to ensure the level of A&G costs incurred and expected to be incurred is reasonable, compared to our peer utilities in Florida.

Q. Then, please explain the comparison of FPU's budgeted A&G expense to the historical benchmark.

A. There are four main factors contributing to the increase in A&G expense. First, there are two notable reclassifications of costs between the historic benchmark and the projected test year. In the projected 2015 test year, $66,156 of common depreciation expense was included in Account 921 in 2013. In the benchmark year, the common depreciation was charged to Account 403-Depreciation expense. In addition, in the 2015 projected year, rent expense of $124,609, which was not included in the benchmark year, was added. The inclusion of this rent expense is due to the sale of the West Palm Beach administrative office and the rent expense allocated from corporate facilities. The increase in rent expense is offset by reductions to rate base, depreciation expense, and taxes other than income that would have been included if the West Palm Beach corporate office was not sold. Second, in the 2015 projected year, administrative and general expense was increased by $120,000 to establish a general liability reserve. This reserve is in lieu of purchased insurance and to reduce the volatility associated with periodic claims. Third, IT costs also increased by approximately $350,000 to address increased compliance, security, data and network requirements, as well as to maintain enhanced system, website and software needs.

Finally, the remaining increase is due primarily to additional travel costs, higher costs associated with maintaining administrative facilities as a result of improved quality of those facilities, and expanded corporate functions and services not previously available to FPU. Travel costs have increased because of centralization of the Florida staff, additional training available to employees and increased focus in customer service and employee satisfaction, which require managers to travel to all locations within Florida. The transfer of certain A&G functions to the corporate office in Delaware for increased quality and efficiency has also necessitated additional travel. The increases in A&G expenses related to establishing a general liability reserve, additional IT requirements and expanded corporate functions and services, as well as their benefits to FPU and its customers, which are discussed in more detail below. These increases in A&G expenses provide FPU with the appropriate level of administrative support necessary to manage its business and provide the superior service to its customers. These increases are partially offset by efficiency and effectiveness gained in other areas of the Company. For example, the efficiency gained by combining the accounting and finance function with the corporate office allowed FPU to comply with the Sarbanes-Oxley requirements without incurring any additional costs (FPU was required to comply with the Sarbanes-Oxley requirements for the first time in 2009 and was expected to incur significant costs on its own as a result). Strengthening management oversight and enhanced treasury/finance capability allowed FPU to make necessary improvements in its electric system in the past several years to enhance reliability, which reduced maintenance expenses in the projected test year. These are just a couple of examples of how the expanded administrative functions and capabilities reflected in higher A&G expenses have helped FPU and its customers to benefit from lower costs or avoided costs in other areas.

Q. Please explain the general liability reserve.

A. With the help of an outside broker, Chesapeake assesses the Company's current risks, insurance needs and costs in determining the appropriate level of insurance coverage. The Audit Committee of Chesapeake's Board of Directors reviews Chesapeake's insurance coverage, the current insurance environment and related information to ensure it has the appropriate and necessary level of coverage. In the past five years, FPU's electric operation had one large insurance claim, which was settled for $2.75 million. Chesapeake's general liability insurance policy, which also covers FPU, had a maximum deductible of $250,000 per each claim. Since Chesapeake's general liability insurance policy covered this claim, FPU's financial exposure was capped at $250,000, which was the maximum deductible amount it had to pay. FPU's electric rates currently in place did not include any cost associated with general claims against the Company. As a result, the $250,000 deductible paid by FPU in this case has not been recovered. FPU is requesting recovery of $250,000 paid to satisfy the deductible requirement under the insurance policy over a five-year period. In addition, FPU is requesting an additional $250,000 to be included in the next five-year period to establish the general liability reserve sufficient to cover another potential claim with the similar financial exposure that may arise during that period, as well as $20,000 per year to cover any other smaller general liability claims.

Q. Please describe in more detail the increased IT costs.

A. Since 2008, FPU has been facing the increased needs to maintain network security, data integrity and system functionalities. A newly emerging threat of cyber attacks and increased functionalities of the Company's website and key systems (accounting, billing, payroll, etc.) are just some examples of those needs that have necessitated additional IT costs to expand network infrastructure and strengthen hardware and software maintenance. Chesapeake, like other businesses and utilities, has strengthened its IT software, hardware and network infrastructures to ensure the additional functionalities and increased use of its key financial, billing and other systems can be maintained in a safe manner without interruption. IT has also increased its staffing, as well as the expertise of its staff, to address this increased risk and demand for service. FPU has benefited from Chesapeake's increased IT infrastructure as it has enabled FPU to provide better customer service through enhanced website, more secure customer billing and other information, accurate and more timely financial information, and ability to engage customers and employees from remote locations.

Q. Please provide specific examples on how the expanded corporate A&G functions provided by Chesapeake benefit FPU's customers?

A. Expanded corporate A&G functions have benefited FPU and its customers in many different ways. Chesapeake's corporate communications team provides increased awareness of the Chesapeake and FPU brand through emphasizing core values and translating them into superior customer service. The communications team has assisted FPU in its effort to redesign the Company's website to enhance its look, content and functionality to better and more easily engage customers, thereby allowing customers to obtain accurate and more focused information through the website. For example, FPU's customers can utilize the website to make billing inquiries, request services, make payments and report power outages. They can also get energy saving ideas and information on electric rebates and incentives currently available. It has also assisted FPU with initiatives to increase its engagement with customers and communities, as well as employee satisfaction and training. Another corporate initiative benefitting FPU's customers is the Service Excellence initiative, which emphasizes customer service, engagement and satisfaction. Chesapeake's corporate office coordinates and provides necessary training to employees for the Service Excellence initiative and develops specific plans to measure and improve customer satisfaction. Business development is another example of the expanded corporate A&G functions now available to FPU. Business development assists the electric operations to assess alternative fuel supply options and provides market research data. It also coordinates the corporate-wide initiative to automate the infrastructure mapping to increase efficiency and reliability of the Company's system. Lastly, Chesapeake's management and Board of Directors also bring increased oversight of FPU's businesses and management. For example, Chesapeake's Board of Directors and senior management have seven people with over fifteen years of energy and utility industry experience. One director in particular has over 30 years of experience in the electric utility, generation and marketing industry and brings in-depth knowledge of regulations and power delivery. In addition to the industry knowledge, another director, for example, has extensive knowledge of best practice in human capital and customer experience, which helps FPU's effort in those areas. Four of Chesapeake's eleven independent directors are based in Florida to provide valuable business, regulatory, financial and other insights unique to Florida. All these examples of the expanded corporate functions and services have allowed FPU to continue its effort to enhance customer experience, improve employee education, and develop strategies, all of which are for the direct benefit of our customers.

Q. How does Chesapeake review the level of compensation for its officers?

A. Compensation of the named executive officers of Chesapeake, which include Chesapeake's President and Chief Executive Officer, Senior Vice Presidents and the President of FPU, is reviewed by the Compensation Committee of Chesapeake's Board of Directors. The Compensation Committee engages an outside consulting firm to review executive compensation. In March 2013, the Compensation Committee reviewed base salaries of the named executive officers based on a market analysis prepared by a third-party compensation consultant. Compensation of the named executive officers and related information, including the review of the

Compensation Committee, are disclosed in Chesapeake's proxy, which was filed with the Securities and Exchange Commission.

Q. Why is it important that FPU be allowed to recover the costs associated with corporate A&G through base rates?

A. The corporate A&G functions are integral part of FPU's ability to support its operations, comply with legal, regulatory and other requirements, finance the necessary capital required to maintain and grow its business, engage its customers to provide superior customer service, address complex financial and business issues and provide appropriate management oversight. As it was previously mentioned in my testimony, many of the A&G functions previously performed by FPU were combined with or transferred to Chesapeake's corporate office since the merger in 2009 for increased quality and efficiency. The corporate A&G functions allow the Florida electric operation to focus on its day-to-day business of serving its customers without burdening itself with having to establish and maintain separate support functions. By receiving support from the corporate office, which has expanded resources and capabilities, FPU benefits from superior quality of service, efficiency, more in-depth knowledge, higher level of professional service and increased ability to handle more complex and challenging business and compliance issues.

Income Taxes

Q. How was income tax expense determined?

A. Total income tax expense consists of income taxes currently payable and deferred income taxes. The currently payable income taxes for the projected test year were calculated by simply multiplying the currently effective income tax rate by the income that is currently taxable. Currently taxable income was calculated by deducting from the projected test year net operating income before income taxes, the interest expense inherent in the cost of capital and other permanent and temporary timing differences.

Q. What is the effective income tax rate of FPU?

A. Since the merger with Chesapeake in 2009, FPU has been a member of a consolidated federal tax return with Chesapeake and its other subsidiaries. Chesapeake's federal statutory income tax rate is 35 percent, which is effectively the federal statutory rate for FPU. FPU continues to file a separate state income tax return in Florida. Florida's statutory income tax rate is 5.5 percent. After taking into consideration the federal deduction of the state income taxes paid, the effective income tax rate for FPU is 38.575 percent.

Q. Please explain how you derived the projected amount for deferred taxes.

A. Deferred income taxes represent the tax effect of temporary differences between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable amounts or deductible amounts in future years when the reported amount of the asset is recovered or when the reported amount of liability is settled. The projected amount of deferred taxes were calculated by reviewing all existing timing differences and projecting the amount of timing differences that are expected to originate and reverse. The projected amounts of deferred taxes were added to the deferred income tax balances at the end of the historic base year. For example, in projecting deferred taxes related to plant, we estimated the tax depreciation of existing and new plant assets in service during the projected period (originating) and the book depreciation of the same plant assets during the same period (reversing). The difference, which is the change in a timing difference, was multiplied by the effective income tax rate to estimate the change in deferred taxes in the projected period.

Q. Please explain the South Georgia adjustment for income tax step-up included in this petition.

A. Prior to the merger with Chesapeake, FPU was required to pay federal income taxes at a statutory rate of 34 percent. Since the merger, FPU's statutory rate increased to 35 percent. This increase in the federal statutory rate increased FPU's effective income tax rate to 38.575 percent from 37.63 percent. The tax normalization rules require that utilities maintain their deferred income taxes, in Account 282, at the same income tax rate as the income tax rate used in calculating their income tax obligation to the IRS. This required FPU to adjust its deferred taxes to reflect the increase in its effective income tax rate to 38.575 percent to comply with the normalization rules at the time of the merger. Since FPU had a net deferred tax liability associated with its plant assets at the time of the merger, this resulted in a deficiency in the deferred tax reserve. This deficiency represents the amount of taxes associated with this timing difference, which FPU had previously been allowed to recover under the previous, lower effective income tax rate, that will be paid in the future by FPU at the current, higher effective income tax rate. The South Georgia method is one of the methods of the tax normalization accounting, which allows utilities to amortize the deficiency over the remaining lives of the property that gave rise to the deficiency. The total deficiency, including the appropriate gross-up for income taxes, is $353,307. FPU is proposing this amount to be amortized over 26 years, which is the average remaining life of the plant assets for the electric operation. The annual amortization is $13,589, which is required to comply with the tax normalization rules.

<u>**Pension and Postretirement Benefits**</u>

Q. Please explain how you derived the projected expense for pension and postretirement benefits.

A. The Company estimated the projected expense for pension and postretirement benefits by averaging the expenses in the past years. Due to the significant volatility in the discount rate assumptions in the past years, in which the discount rate assumptions fluctuated as low as 3.75 percent and as high as 5.75 percent, it was difficult to project the appropriate future discount rate assumption. In light of this challenge, the Company decided to use the average of the past four years of its pension expense (four years being the period since the merger with Chesapeake) to estimate the projected pension expense. For the postretirement medical plan, the Company used the average of the past two years since the plan had a significant amendment related to benefits, which was effective on January 1, 2012 (two years being the period since that amendment).

Q. Please explain the amortization of pre-merger unrecognized cost included in the Company's projected expense for pension and postretirement benefits?

A. FPU has accounted for benefit plan costs using accrual accounting in accordance with the Commission's practice, which is based on the accounting requirements under the accounting principles generally accepted in the United States of America (commonly referred to as US GAAP). The issuance of the Statement of Financial Accounting Standard No. 158 ("FAS 158") in September 2006 modified US GAAP for defined benefit employee benefit plans, such as FPU's pension and postretirement medical benefits. FAS 158 requires companies to record as an asset or liability the difference between plan assets at fair value and obligation of the defined benefit plans. In addition, FAS 158 requires companies to record, as a component of other comprehensive income (included in equity), the amount of the net benefit asset or liability that had previously not been recognized in earnings. Upon the issuance of FAS 158, FPU requested, and the Commission approved in Docket Number 080029-PU, the regulatory asset/liability treatment for the unrecognized portion of the benefit asset or liability (in other words, the portion FAS 158 required to be included as a component of other comprehensive income). The merger with Chesapeake in 2009 required a specific accounting treatment associated with defined benefit plans. US GAAP requires the acquisition accounting to recognize the full benefit obligations in excess of the plan asset value (similar to the net asset or liability required to be recorded under FAS 158) without recording the unrecognized portion of the benefit (the portion included in equity, or in FPU's case, regulatory asset). Essentially, US GAAP requires a one-time recognition of any unrecognized benefit costs associated with defined benefit plans at the time of a merger or acquisition. At the time of the merger with Chesapeake, FPU's electric operation had $2,706,958 and $31,450 of unrecognized benefit costs associated with its pension and postretirement medical plans, respectively, which were deferred as regulatory assets pursuant to the Commission's order in Docket Number 080029-PU. The Commission previously allowed a deferral treatment of the accelerated benefit cost recognition pursuant to the acquisition accounting. In Docket Number 060657-GU, Florida City Gas ("FCG") was allowed to defer the amount associated with accelerated pension cost recognition in its acquisition by AGL Resources Inc. and amortize it over the remaining service period of FCG employees expected to receive benefits from the pension plan, which was the period approximating the normal pension expense recognition without the acquisition. Consistent with this treatment approved by the Commission, FPU continued to defer $2,706,958 and $31,450 in unrecognized pension and postretirement medical benefit costs, respectively and amortize them over the remaining service period of FPU employees receiving benefits from those plans (9.88 and 11.30 years, respectively). The resulting amortization is $276,767 per year.

<u>**Cost of Capital**</u>

Q. What is the Company's risk profile?

A. Chesapeake's long-term debt carries the NAIC 1 rating from the National Association of Insurance Commissioners ("NAIC"). According to NAIC, NAIC 1 is assigned to the highest quality obligations with the lowest credit risk. The NAIC 1 rating is equivalent to an A-bond rating or above for Moody's and S&P ratings.

Q. What is the capital structure of the Company?

A. The calculation of capital structure reflects investor sources of capital as follows: common equity of 58.21 percent, long-term debt (including the current maturity) of 35.29 percent and short-term debt of 6.50 percent. Chesapeake targets an equity ratio to total capitalization of between 55 and 60 percents. These targets have been reviewed with Chesapeake's Board of Directors.

Q. Why does the Company believe this structure is appropriate?

A. The capital structure is based on the historic capital structure as of September 30, 2013, and is updated through the end of the projected test period based on our most recent projection of capital requirements. The projection incorporates long-term debt placements committed by Chesapeake in 2014 and anticipated in 2015, as well as anticipated equity issuances necessary to maintain the desired ratio of equity to total capitalization between 55 to 60 percents. Also, the common equity ratio of 58.21 percent is consistent with the historic ratio in the past five years. The common equity ratio to the total capitalization as of December 31, 2013, 2012, 2011, 2010 and 2009, excluding accumulated other comprehensive income, which is further discussed in the testimony of Mr. Moul, was 55 percent, 60 percent, 62 percent, 59 percent and 56 percent, respectively. The simple five-year average for those five years was 58 percent.

Q. What is FPU's role in the decision-making process regarding financing for FPU?

A. Except for the remaining Secured First Mortgage Bond of $8 million issued by FPU prior to the merger, all of FPU's financing is provided by Chesapeake. FPU's financing needs are considered, along with the needs of Chesapeake's other subsidiaries, in establishing Chesapeake's financing plan and executing the associated financing strategy. Chesapeake has various budget, forecast and other planning processes that allow each of its businesses, including FPU, to present its capital requirements. Since Chesapeake finances with the consideration for the financing needs of all of its subsidiaries, including FPU, FPU's financing decisions are consistent with those of Chesapeake in terms of capital structure, terms and conditions. Chesapeake has directly assigned the one remaining series of FPU's Secured First Mortgage Bond to FPU as it was financed by FPU prior to the merger with Chesapeake. The remainder of FPU's capitalization is represented by the relative proportions of Chesapeake's components of capitalization as Chesapeake provides all of FPU's other financing needs.

Q. Has the merger with Chesapeake had an impact on FPU's overall cost of capital?

A. Yes, with Chesapeake's sound capital structure and superior ability to attract capital at reasonable cost, the merger has had a positive impact on FPU's overall cost of capital. Prior to the merger, FPU's credit rating (long-term debt rating of NAIC 2) and inability to access capital market at attractive rates impaired its ability to obtain the necessary capital to grow. By comparison, Chesapeake's long-term debt rating was (at the time of the merger) and continues to be NAIC 1. At the time of the merger, FPU had only one committed line of credit for $26 million. Chesapeake currently has access to short-term debt facilities totaling $165 million. In addition, FPU had obtained only $29 million of long-term debt financing over the 10-year period immediately prior to the merger. By contrast, in less than five years since the merger, Chesapeake has issued $56 million in long-term unsecured debt with an additional $50 million committed to be issued in May 2014. The debt issuances have been consummated at attractive interest rates ranging from 3.73 percent to 6.43 percent and on an unsecured basis with much less stringent covenants. Since the merger, Chesapeake successfully refinanced all but one series of FPU's Secured First Mortgage Bonds with Chesapeake unsecured senior notes and reduced the overall cost of debt.

Q. Does this conclude your testimony?

A. Yes.

Exhibit No._______
MK-1
MFR'S Sponsored by Matt Kim

MFR Number	Title
B-22	Total Accumulated Deferred Income Taxes
B-23	Investment Tax Credits-Annual Analysis
C-22	State and Federal Income Tax Calculations
C-25	Deferred Tax Adjustment
C-26	Income Tax Returns
C-27	Consolidated Tax Information
C-28	Miscellaneous Tax Information
D-1a	Cost of Capital-13 Month Average
D-1b	Cost of Capital-Adjustments
D-2	Cost of Capital-5 Year History
D-3	Short-Term Debt
D-4a	Long-Term Debt Outstanding
D-4b	Reacquired Bonds
D-5	Preferred Stock Oustanding
D-6	Customer Deposits
D-7	Common Stock Data
D-8	Financial Plans-Stocks and Bond Issues
D-9	Financial Indicators-Summary
G-16	Interim Pension Cost
G-19a	Interim Cost of Capital-Year End

FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS
OF
OF ALEIDA SOCARRAS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Aleida Socarras. I am Director of Marketing & Sales for Florida Public Utilities Company (the "Company" or "FPU"). My business address is 911 South 8th Street, Fernandina Beach, FL 32034.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined Florida Public Utilities in March 2011. Prior to joining Florida Public Utilities Company, I was Senior Sales Manager of TECO Partners, a Florida sales and marketing company representing multiple energy related companies. Prior to that, I worked for TECO Peoples Gas in various management positions. I hold an M.S. degree in Organizational/Industrial Psychology from the University of Texas at El Paso.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Director of Marketing & Sales, I am responsible for the Company's marketing, sales and energy conservation departments, providing leadership for the Company's growth strategy and program and business development efforts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A, My testimony addresses the critical role that FPU plays in promoting economic development in areas we serve and the corresponding benefits to consumers. The Company's Marketing & Sales team and the Company overall builds strong strategic partnerships with FPU's business and industrial customers and advises on conservation and energy efficiency measures. I explain the Company's approach to economic development and our desire to be a leader in assisting the areas we serve advance their economic development efforts. Finally, we propose in this rate case that the Commission approve our Economic Development Rider. I discuss the specifics of our request and explain how the rider will promote economic development.

Q. HAVE YOU FILED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION IN PRIOR CASES?

A. No. I do, however, regularly participate in the development of the Company's proposals and programs addressed in the Commission's Natural Gas and Energy Conservation Clauses.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit AS-1, which is a description of our electric economic development program. I also sponsor Exhibit AS-2, which contains the proposed tariff sheets and service agreement for the economic development rider component of our economic development program.

Q. ARE YOU SPONSORING ANY MFRS IN THIS CASE?

A. No, I am not.

Q. PLEASE EXPLAIN THE ROLE THAT FPU HAS IN ECONOMIC DEVELOPMENT.

A. As described in Rule 25-6.0426, Florida Administrative Code, economic development activities are those activities designed to improve the quality of life for all Floridians by building an economy characterized by higher personal income, better employment opportunities, and improved business access to domestic and international markets. To this end, the Company's Marketing & Sales team, and the Company overall, builds strong strategic partnerships with FPU's business and industrial customers and advises on conservation and energy efficiency measures. We work closely with regional economic development organizations, chambers of commerce, and trade associations to promote our service areas. We aggressively encourage new business growth and assist with retention and business expansions activities. By helping businesses reduce their energy costs and identifying and instituting energy efficiency measures, we help them become more competitive and prosper. This maintains and adds jobs to the local economy which in turn benefits the community and all rate payers.

Q. PLEASE EXPLAIN THE BENEFITS OF ECONOMIC DEVELOPMENT TO FPU'S CUSTOMERS.

A. Economic development activities improve quality of life in the communities we serve by creating jobs, expanding economic opportunities, and positively influencing demand for energy consumption. At the same time, economic growth creates a greater pool of users and additional wealth for communities to invest in energy efficiency measures. Economic development efforts in our areas have resulted in economic development organizations having a resource at their disposal to provide prospective businesses with infrastructure assessment, technical information, rate comparisons, and assistance in site identification where infrastructure is already in place to help expedite site certification. This assistance can help mitigate risk for prospective businesses and speed up the process.

Our participation in community chambers of commerce, trade shows, and other economic development activities strengthen the communities we serve. Our involvement not only demonstrates support for the community, but provides education and leadership from trained, knowledgeable professionals that can inform decisions made by community leaders. FPU staff members assist in providing business recruitment leads, researching prospects and target markets, and in providing data gathering and analysis. These collaborations also provide opportunities to address and promote conservation efforts. In addition, by hosting events and participating in community forums, we help share and disseminate information which helps increase cooperation among stakeholders and creates a positive image of the community. A unified community with a cohesive message helps to make the community more attractive to decision makers looking to the community as a place where they want to live, thereby bringing new businesses and people to our service area. Consequently, additional load added to our system enables us to spread fixed costs over a larger customer base, furthering an efficient system and keeping rates stable for all our customers.

Q. ARE THERE EXAMPLES OF FPU'S EXISTING ECONOMIC DEVELOPMENT INITIATIVES AND BENEFITS THERETO?

A. Yes. FPU has been actively involved with the Nassau County Business Development Board ("NCBDB") for many years through participation on the Board, as well as actively participating in many committees and events. NCBDB relies on us for technical assistance, industry knowledge, and man-hour resources to help them attract businesses and promote the area overall. Also, we work with them to identify business ready sites and provide projected rate analyses. Another example is our cooperation with the City of Marianna in making improvements to the downtown area that is being revitalized. We moved overhead lines near the courthouse, as well as around U.S. Highway 90, in order to make the area more attractive and with the intent of driving visitors towards the downtown area. We also provide educational resources and help promote "Buy Local" campaigns.

Q. PLEASE DISCUSS THE STATE OF FLORIDA'S FOCUS ON ECONOMIC DEVELOPMENT.

A. Governor Rick Scott and the Florida Legislature have strengthened the focus on economic development efforts. Collectively, they encourage all Florida businesses to place a priority on workforce development and job creation. As the Commission knows, the Governor has outlined two major goals for Florida: job creation and decreasing unemployment numbers. Correspondingly, the Commission has taken a leadership role in supporting and facilitating economic development. The Commission has supported efforts by other utilities to promote economic development by allowing recovery of reasonable associate expenses pursuant to Section 288.035, Florida Statutes and Rule 25-6.0426, Florida Administrative Code.

Q. IS FPU PROPOSING ANY NEW ECONOMIC DEVELOPMENT INITIATIVES AS PART OF THIS PROCEEDING?

A. Yes. FPU is seeking approval of our Economic Development Rider. We believe the Rider will further our economic development efforts and result in greater customer benefits in our service areas. When companies consider areas for relocation or expansion, electric rates are often a major consideration. By providing a rate discount, we will be able to assist the state and specifically our service area in being more competitive. Electric rate discounts are expected as part of the incentive packages offered to prospective companies evaluating an area of relocation or expansion.

Q. PLEASE DESCRIBE YOUR REQUEST.

As I have noted, for many years, FPU has been involved in economic development activities in the areas of the state in which we serve. In light of the current economic climate, FPU has concluded that we should further extend our efforts in economic development. To that end, we intend to implement a more robust, detailed and formalized Economic Development program to enhance even further our work to promote economic development. I have outlined below our Plan's components, the key to which is our Economic Development Rider Program.

Q. PLEASE BEGIN BY OUTLINING THE AVAILABILITY AND APPLICATION OF YOUR ECONOMIC DEVELOPMENT RIDER PROGRAM.

A. We intend to make the Economic Development Rider Program (the "Rider Program") available throughout the entire territory served by FPU. The Qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider. This Program would apply to new electric load associated with:

(1) Initial permanent service to new commercial and industrial establishments;

(2) Commercial or industrial space that has been vacant for more than six months prior to the application for service under the Rider Program; and

(3) The expansion of existing establishments.

The purpose of this new Rider Program is to provide an attractive service discount offering for commercial ventures considering locating their business or new facilities in areas within FPU's service territory or considering expanding existing facilities in a manner that will create new job opportunities for communities we serve. Notably, the jobs created by a new facility or facility expansion must be full-time positions that continue to exist as long as the customer takes service under the Rider Program, which can be up to five (5) years.

Q. HOW WILL YOU DETERMINE WHAT QUALIFIES AS NEW LOAD?

A. The new load applicable under this Rider Program for new and vacant establishments must be a minimum of 200 kW at a single delivery point added after December 31, 2014. In the case of the expansion of existing facilities, the added new load must be a minimum of 100 kW; however in order to qualify, the total load after the addition of the new load must be a minimum of 200 kW at a single delivery point. To qualify for service under this Program, the Customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added. Additionally, in order to take service under the Program, the Customer must provide sufficient evidence to FPU to establish that the availability of the Program is a significant factor in the Customer's location or expansion decision.

Q. WILL YOU MAKE THE RIDER PROGRAM AVAILABLE TO EXISTING LOAD?

A. No. Initial application for this Rider Program is not available to existing load. However, if a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits outlined below. The Program is not available, however, for load shifted from one establishment or delivery point on the FPU system to another one on the FPU system.

Q. WHAT ARE THE TERMS AND CONDITIONS FOR RIDER PROGRAM PARTICIPATION?

A. The specific rates, term of service, and service agreement are included in Exhibit AS-1 attached to my testimony and are similar to programs approved by the Commission for other electric utilities. To summarize the Rider Program, customers will be required to sign a five (5) year contract, which will not be eligible for renewal. The customer will, for that period of time, continue to take service under the tariffed rates and charges for their applicable rate class, but a percentage discount will be applied to the demand and non-fuel charges. The discount applied will gradually be reduced each year of the contract to zero in the final year. Throughout the contract period, the customer will still pay the applicable customer charge and any amounts associated with cost recovery clauses.

Q. WHAT ARE THE COMPONENTS OF FPU'S OVERALL ECONOMIC DEVELOPMENT PROGRAM?

A. As indicated, the Rider Program is but one piece of our plan to enhance our economic development efforts. In addition to the Rider Program tariff included in my Exhibit AS-2,, FPU's Economic Development Program will memorialize and promote our commitment to provide: 1) economic development assistance to the communities we serve; 2) recruitment resources for potential new businesses considering location options; 3) direct community involvement by FPU in key areas that attract new business; 4) leadership, as appropriate, on community chambers and economic development boards; 5) active involvement in commercial retention and programs developed in cooperation with local chambers of commerce; 6) programs, leadership and cooperation to encourage innovation in community economic development programs; 7) resources to enhance k-12 education, particularly in areas, such as STEM, that attract business; 8) resources and cooperation in community initiatives to promote sustainable practices; 9) active engagement on neighborhood revitalization programs; and 10) programs and information geared towards enhancing resiliency to disasters.

Specifically, FPU will provide assistance to local economic development organizations by providing information and resources, including timely responses to requests for information regarding data and infrastructure assessments, communication and assistance in the creation of a "business-ready" environment, as well as assistance in efforts to certify "shovel ready" construction sites. The Company will also encourage and participate in site visits, as well as recruitment and prospecting missions to showcase communities in our service areas, and provide financial assistance, as necessary, to support and strengthen these efforts.

FPU will also be engaged in offering assistance to businesses considering locating in our service areas. FPU will commit to providing prompt responses to new business inquiries regarding our service offerings, as well as information and technical guidance regarding the availability and requirements of gas and electric infrastructure for prospective new businesses. In addition, the Company will assist prospective business customers with projected rate analyses, review of reliability requirements, and back up powers supply, as needed.

FPU's broader community involvement will include active efforts to gain a greater understanding of the needs of the various communities we serve and work with communities and local governments in the development of community-specific economic development plans. FPU will also be engaged on community economic development boards and local chambers of commerce, providing leadership and financial resources as needed. The Company will also provide outreach and seminars regarding Florida's energy market and correlating opportunities for businesses.

In addition to efforts targeted at attracting new businesses, the Company will also undertake additional efforts to retain existing commercial enterprises, including commercial energy conservation rebate programs and energy audits, as well as active participation in retention and small business support programs promoted by local governments and chambers. We will also participate in the development and implementation of "Buy Local" campaigns, among other things.

Q. DOES YOUR ECONOMIC DEVELOPMENT PROGRAM INCLUDE ENGAGING SCHOOLS AND CHILDREN?

A. Yes. The Company's efforts will extend into the education arena through coordinated efforts to develop school programs that will build a stronger workforce in those areas most critical for attracting business opportunities. FPU will also engage direct with students through mentoring projects targeted at Science, Technology, Engineering, and Math ("STEM") programs and provide financial assistance as appropriate.

Q. ARE THERE ADDITIONAL EFFORTS NOT PREVIOUSLY DISCUSSED?

A. Yes. FPU will also develop programs, as well as Company policies, designed to encourage technical innovation, particularly as it relates to the development of viable renewable and cogeneration projects and installation of electric recharging stations.

FPU's program will also promote best practices for energy sustainability and include publications, seminars, and direct-mail marketing campaigns designed to encourage conservation, as well as economic growth.

As another means of attracting businesses to our communities, FPU will coordinate with communities engaged in neighborhood revitalization programs and assist by providing assistance with neighborhood enhancements such as improved street lighting and tree trimming. The Company will also provide communities with information and resources to assist in the pursuit of state and federal incentives and grant funding for community development projects. FPU will also actively engage in developing and implementing disaster resiliency initiatives, including locating back-up power supply and supporting emergency response drills.

All in all, each aspect of our overall Economic Development Plan is designed to assist communities that we serve in presenting the most compelling location package to businesses considering location options.

Moreover, our Plan is consistent with the Commission's Rule 25-6.0426, F.A.C., in all respects. Consistent with that Rule, financial support provided by the Company will only be pursuant to a prior written agreement. Likewise, the Company will only seek recovery of economic development expenses that are consistent with the limitations set forth in paragraph (7) of the Rule.

Q. WHAT IS THE STANDARD BY WHICH THE COMMISSION CAN APPROVE YOUR REQUEST?

A. Section 288.035, Florida Statutes, allows the Commission to authorize utilities to recover reasonable economic development expenses.

Q. CAN YOU DEFINE REASONABLE ECONOMIC DEVELOPMENT EXPENSES?

A. The Legislature has defined "reasonable economic development expenses" as: 1) expenditures for operational assistance, including the participation in trade shows and prospecting missions with state and local entities; 2) expenditures for assisting the state and local governments in the design of strategic plans for economic development activities; and 3) expenditures for marketing and research services, including assisting local governments in marketing specific sites for business and industry development or recruitment, and assisting local governments in responding to inquiries from business and industry concerning the development of specific sites. FPU believes that the expenses anticipated are fully consistent with this definition.

Q. WHAT IS THE EXPENSE AMOUNT INCLUDED IN THIS RATE CASE FOR ECONOMIC DEVELOPMENT?

A. The Company is seeking approval of $50,000 annually, which will have a negligible impact on rates to customers. Consistent with Rule 25-6.0426(4), F.A.C., we are asking that the Commission determine that this is a prudent level of economic development expenses for FPU and that this amount may be reported by the Company as such for purposes of its surveillance reports and earnings review calculations. Furthermore, FPU anticipates that some amount of the expenses incurred under this Program will be offset by additional load, allowing the Company to spread its fixed costs across a larger customer base.

Q. WITH REGARD TO THE RIDER PROGRAM, WILL THERE BE ANY LIMITATIONS ON THE NUMBER OF CUSTOMERS ABLE TO TAKE SERVICE UNDER THE TARIFF?

A. Yes. The tariff will initially be open to all customers that meet the service requirements in the tariff. However, in the event that the Company's economic development expenses exceed, in total, the amount approved for the Company in accordance with Rule 25-6.0426(3), F.A.C., the Rider Program will be immediately closed to new applicants.

Q. DO YOU BELIEVE THE COMPANY'S REQUEST MEETS THE PARAMETERS OUTLINED BY THE LEGISLATURE FOR APPROVAL OF ECONOMIC DEVELOPMENT INITIATIVES?

A. Yes.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND THE COMPANY'S REQUESTS IN THIS REGARD.

A. Certainly. FPU is seeking approval to recover $50,000 annually in economic development-related expenses associated with a new economic development program designed consistent with Commission Rule 25-6.0426, F.A.C. Our program is targeted at providing much needed economic development assistance to both our Northeast (Fernandina Beach) and Northwest (Marianna) service areas. The amount requested will have a minimal impact on customer rates, but the efforts undertaken through the program will be significant and beneficial. Moreover, we hope and expect that our efforts will lead to additional growth, jobs, and ultimately, additional customers on our system, which should help to offset some additional expenses. As part of the new program, FPU is also seeking approval of an Economic Development Rider tariff that will provide discounts for new businesses that meet certain load requirements, which in turn will provide an additional incentive for businesses to consider locating in our service areas. FPU's new Economic Development program and Rider Program tariff are consistent with the Commission's rules and similar to programs approved for other Florida investor-owned electric utilities; therefore, we are asking that the Commission approve our proposal and allow the Company to move forward with our economic development efforts.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

FLORIDA PUBLIC UTILITIES
energy for life

FPU'S ECONOMIC DEVELOPMENT PROGRAM

FPU's Economic Development Program is designed to promote economic growth in the communities we serve. For years, we have worked to build strong strategic partnerships with FPU's business and industrial customers and have worked with regional economic development organizations, chambers of commerce, and trade associations to promote our service areas and encourage growth. This program will guide our efforts to promote economic development. The program consists of the following components:

ECONOMIC DEVELOPMENT ASSISTANCE

Assist local economic development organizations by providing information and resources. This includes:

- Timely responses to requests for information regarding data and infrastructure assessments;
- Communication and assistance in the creation of a "business-ready" environment; and
- Assistance in efforts to certify "shovel ready" construction sites.

RECRUITMENT ASSISTANCE

Encourage and participate in site visits and prospecting missions to showcase communities in our service areas and provide necessary financial assistance and resources to support and strengthen these efforts.

Offer assistance to businesses considering locating in our service areas.

Commit to providing prompt responses to new business inquiries regarding our service offerings, as well as information and technical guidance regarding the availability and requirements of gas and electric infrastructure for prospective new businesses.

Assist prospective businesses with projected rate analyses, review of reliability requirements, and back-up power supply, as needed.

COMMUNITY INVOLVEMENT

Direct community involvement in key areas to attract new businesses, including efforts to gain a greater understanding of the needs of the various communities we serve.

Work with communities and local governments in the development of community-specific economic development plans.

LEADERSHIP
Engage on community economic development boards and local chambers of commerce, providing leadership and financial resources as needed.

Sponsor conferences and seminars regarding Florida's energy market and correlating opportunities for businesses.

RETENTION
Participate in retention and small business support programs promoted by local governments and chambers.

Participate in the development and implementation of "Buy Local" campaigns and other activities to support existing businesses.

INNOVATION
Develop programs and company policies that encourage technical innovation, particularly in the development of viable renewable and cogeneration projects and the installation of electric recharging stations.

.DUCATION
Coordinate efforts to develop school programs that will enhance the quality of the local curriculum to help build a stronger workforce and attract new businesses.

Participate in mentoring projects for Science, Technology, Engineering, and Math ("STEM") programs.

SUSTAINABLE PRACTICES
Promote best practices for energy sustainability by utilizing publications, seminars, and direct-mail marketing campaigns designed to encourage conservation, energy efficiency and economic growth.

NEIGHBORHOOD REVITALIZATION PROGRAMS
Support communities engaged in neighborhood revitalization programs and reach-out programs providing assistance with neighborhood enhancements, such as improved street lighting and tree trimming.

Provide communities with information and resources to assist in the pursuit of state and federal incentives and grant funding for community development projects.

RESILIENCY
Engage in developing and implementing disaster resiliency initiatives, including locating back-up power supply and supporting emergency response drills.

EXHIBIT NO. _____

(AS-2)

TO THE TESTIMONY
OF
ALEIDA M. SOCARRAS

ON BEHALF OF

FLORIDA PUBLIC UTILITIES COMPANY

ORIGINAL TARIFF SHEET NOS. 62, 63, AND 64
(ECONOMIC DEVELOPMENT RIDER PROGRAM)

ECONOMIC DEVELOPMENT RIDER PROGRAM-EDRP

Availability:

This Economic Development Rate Program (the "Program") is available throughout the entire territory served by Florida Public Utilities Company. The Qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

Application:

This Program is applicable to new electric load associated with:

(1) Initial permanent service to new commercial and industrial establishments.

(2) Commercial or industrial space that has been vacant for more than six months prior to the application for service under the Program. Verification of vacancy will be established by evidence of no or minimal electric load during the time period in question.

(3) The expansion of existing establishments. For existing establishments, new load is the net incremental load above that which existed prior to approval for service under this Program.

The new load applicable under this Program for new and vacant establishments must be a minimum of 200 kW at a single delivery point. In the case of the expansion of existing facilities, the added new load must be a minimum of 100 kW, however, in order to qualify, the total load after the addition of the new load must be a minimum of 200 kW at a single delivery point. To qualify for service under this Program, the Customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added.

In order to take service under the Program, the Customer must provide sufficient evidence to Florida Public Utilities Company to establish that the availability of the Program is a significant factor in the Customer's location or expansion decision.

Initial application for this Program is not available to existing load. However, if a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits outlined below.

This Program is not available for load shifted from one establishment or delivery point on the Florida Public Utilities system to another on the Florida Public Utilities system.

(Continued on Sheet No. 63)

ECONOMIC DEVELOPMENT RIDER PROGRAM-EDRP (Continued)

Monthly Rate:

The rates and all other terms and conditions of the customer's otherwise applicable rate schedule shall be applicable under this Program. A credit based on the percentages below will be applied to the demand charges and non-fuel (base) energy charges of the Customer's otherwise applicable rate schedule associated with the Customer's new load:

Year 1 - 20% reduction
Year 2 - 15% reduction
Year 3 - 10% reduction
Year 4 - 5% reduction
Year 5 - 0% reduction

The above credit will be deducted from the monthly electric bill as computed in accordance with the provisions of the Monthly Rate section of the customer's applicable rate schedule before application of any discounts or adjustments. All other charges including the customer charge and energy conservation charge will be based on the Customer's otherwise applicable rate. The otherwise applicable rates may be any of the following: GSD, GSLD, or GSLD1.

Term of service:

The Customer agrees to a five-year contract term. Service under this Program will terminate at the end of the fifth year. Florida Public Utilities Company may terminate service under this Program at any time if the Customer fails to comply with the terms and conditions of this Program. Failure to: 1) maintain the level of employment specified in the Customer's Service Agreement and/or 2) purchase from Florida Public Utilities the amount of load specified in the Customer's Service Agreement will be considered grounds for termination.

If Florida Public Utilities Company terminates service under the Program for the Customer's failure to comply with its provisions, or if the Customer opts to terminate service under the Program, the Customer will be placed on their applicable rate schedule with no future discounts or rate reductions.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

(Continued on Sheet No. 64)

ECONOMIC DEVELOPMENT RIDER PROGRAM- EDRP

Service Agreement

The customer is applying for service under the Economic Development Rate Program based upon new or expanded load as indicated below (Check one):

☐ New Load associated with a new commercial or industrial establishment

☐ New Load established in commercial or industrial space that has been vacant for more than six months

☐ Expanded Load associated with an existing establishment

CUSTOMER NAME____________________________________

SERVICE ADDRESS____________________________________

TYPE OF BUSINESS____________________________________

The Customer hereto agrees as follows:

1. For new and vacant establishments, a minimum of 200 kW of measured demand must be added at a single delivery point.
2. For existing establishments that are expanding, a minimum of 100 kW of measured demand must be added at a single delivery point, and the total measured demand after the addition of the new load must be a minimum of 200 kW.
3. In all cases, the customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added.
4. That the quantity of new or expanded load shall be 200KW of Demand.
5. The nature of this new or expanded load is____________________________________
6. That in the case of a new customer adding load to vacant facilities, the commercial/industrial space associated with the new load has been vacant for more than six months.
7. In case of early termination, the Customer shall repay Florida Public Utilities all of the credits provided under the Program to date.
8. To initiate service under this Program on ____________________, ________ and terminate service under this Program on ____________________, ________. This shall constitute a period of five years.
9. To provide verification that the availability for this Program is a significant factor in the Customer's location/expansion decision.
10. If a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits.
11. That in the case of new load established in a vacant facility to provide verification that there is no affiliation with any prior occupant.

Signed:____________________	Accepted by: Florida Public Utilities Company
Title:____________________	Title:____________________
Date:____________________	Date:____________________

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FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS
OF

MARIANA PEREA

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Mariana Perea. I am the Director of Customer Care for Florida Public Utilities Company ("FPU"). My business address is 780 Amelia Island Parkway, Fernandina Beach, FL 32034.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I attended the University of Hawaii from 1976 to 1979 in the field of Travel Industry Management. I continued my studies at the University of Phoenix where I obtained my Bachelor of Science in Business Management and my Masters of Business Administration in 2009. I spent the first twenty years of my career employed by Mexicana International Airlines in a variety of leadership roles concentrating on customer service and operations. I was engaged by Quest Telecommunications for two years as a Resource Allocation Manager. I moved on to American Express for seven years in the area of Business and Consumer Travel Management. I have been employed with the Company in the capacity of Director of Customer Care for Florida, Maryland, and Delaware since March 2011.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Director of Customer Care, I am responsible for establishing the strategy, goals, and objectives for our customer contact centers serving approximately 126,000 customers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. FPU has a great customer service record. We go through in-depth training to ensure our representatives understand and deliver high levels of service. The purpose of my testimony is to describe the improvements that the Company has made to ensure consistency in customer service. I will describe the strategic goals and objectives of the Company in this area, including the initiatives that have been implemented in support of the strategy. Finally, I will discuss the level of customer complaints to the Commission since the last rate proceeding in 2008 for FPU Electric and the impact of recent reliability improvements since the acquisition of FPU by Chesapeake Utilities Corporation.

<u>INCREASED QUALITY OF SERVICE</u>

Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENT TO CUSTOMER SERVICE.

A. We are fully committed to our customers and stand by our values. We aspire to provide excellence in service and caring for the customer and to ensure their experience with FPU is favorable; this is at the core of everything we do. We strive to exceed customers' expectations. The Company's goal is to establish a process to evaluate and implement changes that will result in an even more positive experience for our customers. This experience is defined as one which results in customers not just being satisfied customers; but rather when customers become promoters of our Company. "Promoters" are customers who refer potential customers to our Company, creating retention and profitable growth. In order to achieve this positive customer experience, the Company is committed to consistently exceeding our customers' needs during critical touch points. These touch points include incoming phone calls, walk-in contact, web site visits, billing, energy conservation program, sales & marketing activities, meter turn-on's, leak investigations at the customer premise and other opportunities to interact with customers. The Company has identified, and is implementing, best practices throughout its operational departments that are aligned with the goal of satisfying our customers to the extent that they become promoters. One of the key components required to achieve and maintain the goal of providing a positive customer experience is the gathering of critical performance measurements. The Company has identified many standard metrics that are critical to determining whether we are moving in the direction of providing a positive customer experience. Based on these metrics (speed to answer, call handle time, net promoter score encompassing the areas of field operations and customer contact, and quality monitoring of calls), the Company is able to improve processes, enhance employee training programs, and better focus collateral material messaging that enables the Company to deliberately provide services that meet and exceed customer expectations. This process encompasses all aspects of the Company, from Customer Care to Sales & Marketing to Operations and Engineering.

Q. PLEASE DESCRIBE THE PROCESS UNDERTAKEN BY THE COMPANY TO IMPROVE THE SERVICE QUALITY TO CUSTOMERS.

A. The Company has developed and implemented a Customer Care strategy with a goal to be recognized as an industry leader in the execution of all meter-to-cash activities, including Contact Center services, while ensuring all processes are designed to deliver a positive customer experience. There are four strategic objectives to the plan: 1) Customer Centric – excellent service to our customers is our number one priority; 2) Consistent Quality – we will provide professional, courteous, timely, and accurate service to every customer in a fair, consistent and accessible manner; 3) Efficient and Effective – we will measure and improve work processes by implementing innovative ideas, applying appropriate technology, and training staff to be helpful and knowledgeable; and 4) Accountability – we will use feedback from processes and customers to improve our performance.

Q. WHAT ARE THE SPECIFIC INITIATIVES THAT THE COMPANY IS IMPLEMENTING IN SUPPORT OF THE CUSTOMER CARE STRATEGY?

A. The Company has identified five (5) key initiatives that support the Customer Care strategy: 1) Consolidation; 2) Performance Management; 3) Development and Training; 4) Process Improvement; and 5) Implementation of Technology.

Q. CAN YOU PLEASE DESCRIBE EACH INITIATIVE?

A. Yes. After the acquisition we saw the need for structural change. First, the Company needed to consolidate its Customer Care activities organizationally. Prior to the acquisition of FPU, this function was performed at each physical location, under different managers who utilized different practices, resulting in an inconsistent customer service experience. The Company has now consolidated the Customer Care functions in one department, which meets the first objective of having a singular focus on the delivery of meter-to-cash activities efficiently in a manner that is easy for the customer and produces high-quality service at a lower cost. Second, the Company has established standards for each meter-to-cash discipline and the reporting requirements necessary to provide valuable feedback to those employees performing the activity. By establishing these clear standards, the Company is able to measure and manage performance of its employees as we strive to deliver a positive customer experience. Third, the Company has developed and implemented a series of employee training modules, hired The Profitable Group to perform training, which has provided employees with the skills and knowledge necessary to efficiently and effectively perform their assigned activities. In addition, the Company has contracted the Fred Pryor group for ongoing online training in a variety of areas. Fourth, many employees throughout the Company have been involved in a review of existing processes designed to improve the effectiveness and efficiency of the activities that are performed. As we move forward, feedback from customers and employees and the metrics results will be utilized in a continuous improvement process to move us closer to the strategic objectives of the Customer Care organization. Finally, the Company has made many technology improvements that enhance our ability to provide efficient and effective services to our customers.

Q. CAN YOU ELABORATE ON SOME OF THE TECHONOLOGY IMPROVEMENTS?

A. The Company, since the acquisition by Chesapeake, has implemented the following two technology improvements which provide the foundation for our ability to provide world-class services to all of our customers, including the Electric customers:

- Consolidation of Customer Information Systems (CIS); and
- Implementation of New Telephony Technology.

The Company is currently in the process of evaluating possible implementation of kiosk-based service for 24/7 payment access in a variety of locations across Chesapeake's Florida service platform with priority being focused upon the Electric divisions. Additionally, the Company is reviewing various Interactive Voice Recognition IVR systems for improved telephone payment options and bill information as well as a mobile friendly website for on the go payment processing and service requests.

Finally, the Company is upgrading its billing software to a new browser-based Customer Information System (CIS) version designed to increase the overall customer and user experience. Additional billing options will also be explored to enhance the customer service experience. The CIS utilizes streamlined guided processes that will create consistency in training and call handling. Additional safeguards have been built into the system to improve the accuracy of customer records. Improved reporting capabilities will increase the Company's ability to analyze data, ensure consistency, and provide services that meet and exceed customer expectations. This billing system will be used Company-wide.

Q. CAN YOU DESCRIBE HOW THE CONSOLIDATION OF THE CUSTOMER INFORMATION SYSTEM BENEFITS ELECTRIC CUSTOMERS?

A. In June 2010, the Company integrated the Customer Information Systems of Chesapeake's Florida operations with FPU's system, thus providing a consistent basis from which to operate. In November 2011, the Company completed the integration of all customers into the consolidated CIS system. The current CIS platform allows for the combined company to seamlessly coordinate all Customer Care (customer call centers, billing and collections and meter reading) and field services activities (turn-on's and off's, meter changes, etc.) that impact customers. As such, customer inquiries can be handled by virtually any customer representative. Previously, customers were required to contact the local office for service during normal business hours (8:30 am to 5:30 pm). Now, customers can contact the consolidated call center from 7:00 am to 7:00 pm or the after-hours service during all non-business hours. The consolidation has also allowed the Company to implement best practices, consistent training and, as described below, capture valuable customer service metrics to evaluate our success in providing the best possible customer experience.

Q. HAVE THE CUSTOMERS RECEIVED ANY OTHER BENEFITS FROM THEIR INTEGRATION INTO THE CUSTOMER INFORMATION SYSTEM?

A. Yes. Customers now receive a full page bill from the Company, which clearly describes all components of the bill, compares current usage with previous usage and provides other important information. Customers also receive a return envelope to facilitate payments made by check through the mail. Previously, customers received their bill on a post card sized statement, which contained the minimum required information, with no return envelope. Customers now also have available multiple payment options, including credit and debit cards, electronic funds transfer, payment by phone and, as more fully described below, walk-in payments at a multitude of locations that are available during and after normal business hours and on weekends.

Q. PLEASE DESCRIBE THE BENEFITS CUSTOMERS RECEIVE FROM IMPLEMENTING NEW TELEPHONY TECHNOLOGIES.

A. The Company has finalized the installation of state-of-the-art telephone systems that provide for seamless call center activities from agents located throughout the state, as well as, for the first time, having the ability to collect a wide variety of valuable customer call metrics. Information such as call waiting times, call abandonments and recording of actual customer calls provides us with the measurements needed to continuously improve our ability to provide world class customer service. The ability to provide call options via telephone prompts enables us to provide better specialized service to customers. Customer service representatives are continuing to receive intensive training that enhances their knowledge of all Company-offered programs, such as Energy Conservation programs, and system-based processes that allow for one-call resolution for most contacts.

Q. CAN YOU IDENTIFY AND DESCRIBE OTHER SPECIFIC CUSTOMER BENEFITS BEYOND THE TECHNOLOGY-BASED IMPROVEMENTS?

A. Yes. The Company has enhanced the customer experience through a variety of initiatives designed to benefit customers through improved services. The following specific improvements have been implemented:

- More thorough and more effective Employee Training;
- Implementation of Third Party Payment Centers;
- Online options for service, payments, and information; and
- Utilization of Third Party Providers for Certain Functions.

Q. CAN YOU DISCUSS THE EMPLOYEE TRAINING THAT HAS TAKEN PLACE?

A. Yes. As previously mentioned, the Company has engaged a firm out of Tampa, Florida, The Profitable Group, to provide employee training throughout the Company. Our employees are committed to serving our customers in such a way that our customers become "promoters." With that said, the employee training is specifically designed to enhance employee understanding of the importance of providing quality service to our customers.

Q. PLEASE DISCUSS WHAT THIRD-PARTY PAYMENT OPTIONS THE COMPANY HAS IMPLEMENTED.

A. Recently, the Company executed an agreement with Fiserv, Inc., a global leader in information management and electronic commerce systems and services, to accept utility payments at its network of locations, primarily at over 300 Wal-Mart stores in the state. Additional payment locations are also part of this service arrangement. This is a free service to our customers as the Company pays for any transaction fees imposed by the contract. This diverse and extensive access to payment locations is very convenient for customers and provides all customers, including all Electric customers, access to walk-in payment locations 24/7. This agreement with Fiserv, Inc. provides for a significant enhancement for customers who desire to pay at a walk-in facility.

Q. HOW HAS THE COMPANY UTILIZED THIRD PARTY PROVIDERS TO ENHANCE SERVICE TO CUSTOMERS?

A. The Company has initiated a comprehensive Dealer Network program that actively recruits, trains and provides continuous support for third party providers, such as plumbing and HVAC companies. These providers are able to perform certain functions that have traditionally been provided by Company personnel, such as turn-key operations from service line installation through meter turn-on. This has resulted in more timely customer connections at a lower cost to the Company.

Q. HOW HAVE CUSTOMERS RESPONDED TO THESE SERVICE IMPROVEMENTS?

A. The primary tangible measurement of customer satisfaction is the number of complaints filed with the Commission. Billing and service complaints were minimal prior to the changes (5) and dropped 20% within 3 months of the new implementations. In the last 7 months we have had no service complaints. The Company believes that this is an important indicator that the customers have embraced the changes from the deliberate implementation of the Customer Care strategy, initiative implementations, employee training and other customer service improvements made by the Company.

Q. PLEASE SUMMARIZE THE EFFORTS OF THE COMPANY TO IMPROVE CUSTOMER SERVICE.

A. The Company's Customer Care strategy, described above, is to provide a positive customer experience on a consistent basis. As discussed, the Company believes that it is not enough to have satisfied customers. Instead, the Company believes that a key component of long-term success is to develop the customer relationship to the point where the customer actively promotes the Company to others. In order to achieve the strategy, the Company has implemented several best practices designed to put the Company on a continuous improvement path towards the perfect customer experience. All of these activities are deliberately designed to identify how to create promoters from our customers and to predict what will be required to keep them as promoters in a rapidly changing environment. The Company has implemented an extensive employee training program designed to improve the knowledge and skill sets of employees that provide services to customers. By implementing systems that capture customer information and feedback, the Company will be able to modify the employee training programs and work management processes and procedures that will result in exceeding the needs of our customers. The company has increased staffing levels and operating hours to 7AM-7PM M-F to support servicing capabilities for customers. All of these efforts by the Company have clearly resulted in an improved quality of customer service to the electric Company customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 140025-EI

DIRECT TESTIMONY and EXHIBITS
OF
Robert J. Camfield

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, LLC, located in Madison, Wisconsin.

Q. What is the purpose of your testimony?

A. My testimony covers two major areas. In the first section of my testimony, I present the recommended billing determinants of Florida Public Utilities Company (FPUC, Company) for the test year, October 2014–September 2015. I then present the Company's expected test-year revenues, which are based on the projections of test-year sales quantities. In the second section of my testimony, I address the expected rate of cost inflation facing Florida Public Utilities Company during the 2014 and 2015 period, including the projected test year. This section of the testimony begins by defining the notion of general inflation and discussing the macroeconomic forces that drive cost and price inflation within regional and national economies. The testimony briefly reviews methods for measuring expected inflation over the near-term future—methods which are applied within this immediate rate filing of Florida Public Utilities Company. The testimony then turns to the empirical analysis, reviewing the study results that are presented in an exhibit. The testimony concludes with a summary of findings along with accompanying recommendations.

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

A. Yes. My professional work is focused on the energy industry and includes regulatory economics, cost of capital and valuation, cost analysis including cost allocation, and analysis of energy demand and forecasting. For over thirty-five years, I have been involved in numerous technical and policy issues facing the energy services industry, including electric and gas utilities. 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, cost allocation and marginal costs, tariff design and rate phase-in plans, corporate performance and cost benchmarking, and load and energy forecasts. My consulting assignments include wholesale market restructuring, and the management of power procurement processes. 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 positions of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I hold a master's degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes, I have represented Florida Public Utilities Company in fuel and non-fuel related dockets of the Florida Public Service Commission (Florida PSC) in previous years.

Q. Have you previously testified with respect to cost analysis and revenue requirements?

A. Yes, I have conducted and been involved in numerous public and private cost studies and various analyses regarding electric, gas, and water utilities, and I have testified with respect to various cost and revenue requirements issues, including sales forecasts.

I. Billing Determinants and Test-Year Revenues

Q. Please identify how your testimony regarding test-year billing determinants and revenues is organized.

A. The first section of my testimony is organized as follows:

- History and Forecast of Billing Determinants, starting on page 6.
- Approach to Load and Energy Forecasting, starting on page 8.
- Preparation and Development of Data, starting on page 14.
- Review of Forecast Models, starting on page 24.
- Estimating Test-Year Billing Determinants, starting on page 26.

- Discussion of Key Issues, including Population, Personal Income, and End-Use Technologies, starting on page 28.
- Presentation of Forecast Test-Year Revenues, starting on page 36.

Q. Are you sponsoring exhibits to accompany this section of your testimony?

A. Yes, I am sponsoring the following exhibits in this section:

RJC-1: *Summary of Historical Energy Sales, Northeast and Northwest Divisions*

RJC-2: *Summary Statistics of Estimated Forecast Equations*, shown on separate pages for the Northeast and Northwest Divisions (2 pages)

RJC-3: *Predicted vs. Actuals*, with Number of Customers and Use per Customer shown separately for each of the four major rate classes (RS, GS, GSD, GSLD) for the Northeast and Northwest Divisions (8 pages)

RJC-4: *Changes in Population of Rural Counties, United States and the State of Florida* (2 pages)

RJC-5: *Global Factors Affecting Residential Energy Use: Real Personal Income, Electricity Prices, and the Stock of Energy-Using Technology* (3 pages)

RJC-6: *Projections of Test-Year Revenues*, shown by customer class and month. This exhibit shows the projected revenues for each of the two divisions as well as for the Company's combined electric operations (3 pages).

Q. Please describe billing determinants and the role of billing determinants in the Company's rate proceeding.

A. Billing determinants refer to billing quantities, and include energy sales (kWh), number of customers served, billing demands (kW) for demand-metered customers, and reactive demand for a subset of demand-metered classes. Billing determinants are specific to the Company's customer classes, which include Residential (RS), General Service (GS), General Service Demand (GSD), General Service Large Demand (GSLD), and General Service Large Demand 1 (GSLD1), as well as Outdoor Lighting (OL) and Street Lighting (STL). The Company's larger commercial classes, including GSD, GSLD, and GSLD1, are demand-metered; kilovolt-amperes reactive (kVAR) are recorded and used for billing purposes in the case of GSLD1.

Test-year billing determinants are major elements of the Company's application for a change in tariff prices. First, test-year billing determinants form the basis for estimating test-year revenues. In addition, billing determinants serve as allocators within the process of cost allocation, and the sales basis for the Company's proposed retail tariffs. Also, billing determinants (number of customers, energy sales, and billing demands) are used by the Company to develop cost projections through and including the test-year period.

Q. Can you please review the Company's electricity sales experience over recent years?

A. The Company's electricity sales have declined over recent years, which has also been the experience of many utilities nationally. Moreover, some electric companies have experienced declines in the number of customers served over recent years. The Company's declining sales over recent years are attributable to a slowing growth—if not outright declines—in electricity usage on a per-customer basis.

The Company's sales experience reflects the combined impacts from declines in household incomes during the deep recession of late 2007 through mid-2009, the subsequent extended recovery from abnormally mild weather of selected years including 2013, and the sharp rise in real electricity prices during the 2009–2010 timeframe. The increase in prices is a direct result of the Company's formerly highly favorable power contracts evolving to new terms that reflect the contemporary market expectations of late 2005 through and including 2008. At that time, the demand for electricity was advancing rapidly as a result of the U.S. economy operating somewhat beyond sustainable full employment. These high demand conditions, coupled with tight supply margins and disruptions in fuel transport, precipitated expectations of comparatively high prices for generation services.

Exhibit RJC-1, *Summary of Historical Energy Sales and Billing Determinants, Northeast and Northwest Divisions*, presents the Company's sales over the years 2008–2013, along with the projected sales in the test year, shown without weather normalization of historical data. In the Northeast Division, residential sales are expected to decline from 186 GWh during 2008 to 178 GWh during the 2014/2015 test year, seven years later. Similarly, sales for the GSD class also decline, by 1.3% annually. Sales for the combined GS and GSLD classes rise modestly, by 1.1% annually. For the Northeast Division as a whole, the net result—without accounting for the nearly fourfold decline in GSLD1 sales—amounts to a decline of about 0.5% annually for the seven years shown, from 326.7 GWh in 2008 to 315.4 GWh in the 2014/2015 test year.

Similar historical experience is shown for the Northwest Division, where residential sales decline from 144 GWh during 2008 to an expected 127 GWh for the test year, a decline of 1.8% annually over these seven years. For the business classes within the Northwest Division, only GSLD sales are predicted to rise—by 0.3% annually over seven years. Taken as a whole, sales in the Northwest Division are expected to decline by 1.0% annually for the 2008 through 2014/2015 period.

Q. How can projections of test-year billing determinants be estimated?

A. Billing determinants (sales) can be estimated in several ways. First, sales trends over historical years can be extrapolated over future years. Second, time series methods, such as autoregressive moving averages (ARMA), are useful for determining short-term forecasts—three to six months forward. Third, structural models, estimated using conventional and well-founded statistical methods, constitute a proven and often-applied approach. In selected cases, time series components can be integrated within structural models.

Generally speaking, trend-based methods are appropriate when the data series (sales, number of customers, and demands) change over time in smooth and easily predictable patterns. Trend-based forecasts also provide a means to check and verify the forecast results obtained through other means.

Q. For the immediate proceeding, how are the Company's test-year billing determinants estimated?

A. Billing determinants are estimated from structural models, using a statistical methodology commonly referred to as regression analysis. Structural models are particularly well suited to the task of estimating electricity demand.

Q. How are structural models applied? Please describe the framework used for determining billing determinants.

A. The methodology underlying the Company's forecast of test-year billing determinants is referred to as a *Use per Customer-Number of Customers* (UPC) approach. This approach recognizes that the decisions and choices of economic agents (households, private firms, and public institutions) driving electricity sales are twofold and separable: first, the decisions on location and facility siting (e.g., new sub-divisions built to satisfy the demand for single-family dwellings); and second, the decisions regarding the consumption of electricity, which are derivative to consumer and business valuations of electricity-using technologies. These valuations are essentially assessments of whether the net benefits are sufficient to warrant the expenditure for the purchase and operation of residential appliances and business technologies.

The UPC approach can be applied with monthly frequency, thus allowing for estimation over more contemporary timeframes. For purposes of analysis, the reliance on recent experience (2004–2013), in isolation from the longer-term history, is important if the underlying relationships between energy consumption and causal factors are evolving gradually over time. Additionally, the UPC approach with monthly frequency captures the composition of regional electricity markets in more depth. In so doing, the UPC approach allows for better diagnostics, thus facilitating an improved understanding of the underlying relationships among sales, demands, and explanatory factors.

For the purpose of developing the Company's load and energy forecast models, specific features of a UPC approach include the following:

- Marginal real price of electricity.
- Weather factors, constructed as the weighted combination of daily heating degree days (HDDs) and cooling degree days (CDDs) over the 60 days of current and previous months covered within billed energy for the current month.
- Monthly identifier variables (binaries), covering eleven months.
- Real personal income and its components (population and per capita income).
- Other factors correlated with electricity consumption. These factors may be orthogonal within the data set, and thus prove to be statistically significant, but may not be inherent causal drivers within the context of a regional economy. Examples include various employment metrics and housing starts for the relevant region.

Q. Are there specific concerns and issues regarding the estimation of the Company's test-year billing determinants and revenues?

A. Yes, there are two overarching concerns. First, the estimation process should not reach back too far historically, if the underlying relationships among the variables in the data set are evolving gradually. Second, forecasts covering small regions are less able to account for the risk associated with random events within small, regional economies.

For sales forecasting, the appropriate starting point is an understanding of the fundamental factors that determine electricity demand, and the particular characteristics and features of the Company's markets. To the degree possible, the sales forecast should take account of the generic structural factors that drive sales/billing determinants, including the underlying forces taking place within the relevant regional economies as well as expected electricity prices and weather conditions. A major factor within the residential class is the technological advancement of electricity-using household products, inducing corresponding gains in energy efficiency. Moreover, in the immediate case, the forecasting process must take account of the directional change of the Company's energy sales—from rising to declining sales—within the estimation period, 2004–2013. This sales trend appears to be a combined result of a contraction in economic activity (the recession in Florida and the Southeast U.S.) and rising electricity prices, as mentioned above. However, a long-term secular trend of declining sales appears to be setting in within the

Company's Northwest Division.

Q. Would you please describe the forecast process for estimating the Company's test-year billing determinants and revenues?

A. Yes. The estimation of billing determinants and revenues involves a five-step process.

Step 1: <u>*Identify the likely factors that determine electricity sales*</u>. As alluded to above, the relevant factors for consideration include *demographic and related factors,* such as population and civilian labor force participation; *economic factors,* such as the income of households (often referred to as personal income) and total employment; *weather factors* represented by CDDs and HDDs; *marginal prices of electricity*; and the *timeframe*, including month specificity (monthly binary variables) and time trends.

Step 2: <u>*Gather and prepare data associated with the factors identified in Step 1*</u>. The identified factors can be referred to as *energy sales drivers* (drivers). For the task at hand, the estimation of billing determinants for the test year, historical data that may serve as relevant sales drivers are gathered and organized into a billing determinants data set.

Step 3: <u>*Estimate forecast models*</u>. The data set assembled in Step 2 serves as the basis to estimate the Company's sales forecast models. The models are linear equations developed to capture the underlying statistical relationships between billing determinants (number of customers, use per customer, and billing demands) and the identified explanatory factors.

Step 4: *Determine test-year sales*. Using the forecast models estimated in Step 3, test-year billing determinants are projected based on the energy sales drivers, as forecasted for the test period (October 2014–September 2015).

Step 5: *Incorporate appropriate adjustments and calculate test-year revenues*. Projections of sales for the test year are adjusted downward for 1) expected conservation within the residential class; 2) the expected natural gas penetration within the residential class served by the Northeast Division; and 3) the change in tariff prices, as filed for, within the Company's petition for an increase in tariff rates.

Q. Does the process outlined above align with contemporary industry practices for sales forecasting?

A. Yes, the forecast process and general approach conform to current practices, industry-wide. That is, linear and non-linear statistical methods are commonly used by electric and gas service providers to develop near-term projections of billing determinants, and also long-term sales forecasts used within resource planning processes.

For the purposes here, the Company's projections of electricity billing determinants are estimated in monthly frequency over the 2004–2013 timeframe, and consist of number-of-customers and use-per-customer models for the four major rate classes (RS, GS, GSD, and GSLD). In addition, statistical models are also used to estimate billing demands for the GSD and GSLD classes. At a class and division level, the historical data for number of customers and use per customer are drawn from the

Company's billing records. Forecast billing determinants for the GSLD1 and lighting classes (OL, STL) are determined by applying trend-based methods, where historical trends are used to project sales in the future. Historical data for GSLD1 and the lighting classes are also drawn from the Company's billing records.

Q. Please elaborate on Step 1, identifying the factors used to estimate the statistical models, for forecasting the Company's test-year billing determinants.

A. As implied above, the demand for electricity within defined service territories of utilities is driven by key explanatory factors, including the size of the underlying regional economy, as reflected in well-known measures such as personal income and regional gross product, and descriptive metrics such as population and civilian employment, including private and public sector employment. Personal income covers the income available to households in a region, and includes wages and salaries, interest on savings and investment, and transfers including social security and unemployment insurance payments. As mentioned, weather factors consist of CDDs and HDDs but can also include other metrics such as the level of humidity and, in some locales, wind velocity. Finally, the price of electricity measured in real terms is found to be an important explanatory factor.

Q. Please discuss the gathering and preparation of data under Step 2.

A. Once the factors have been identified, the forecast process involves the collection, organization, and preparation of data, including key transformations. This Step 2 work is discussed below for each of the several data types.

Regional Demographic and Macroeconomic Factors: The Company's number-of-customers and use-per-customer forecast models incorporate monthly estimates of the population of the counties relevant to the Company's Northeast and Northwest electric service territories. The Bureau of the Census estimates county population annually. The Census Bureau's population estimates for the relevant counties provide the basis for determining the monthly change in population over the course of the year.

For personal income, the forecast process draws upon two main sources of data: the Bureau of Economic Analysis county-level personal income and its components; and the Bureau of Labor Statistics quarterly estimates of average weekly wages and salaries (earned income), and employment. The annual estimates of personal income at the county level reach back several decades, although the immediate work utilizes the more contemporary period, 2001 through 2012, and our preliminary estimates for 2013 are based on trend experience. As mentioned, the annual, county-level personal income metrics are based on earned income and other elements, including transfers and the interest on financial holdings (return to financial assets). For small areas such as rural counties, earned income, driven by both wages and employment, varies over the course of the year as a result of seasonal and macroeconomic forces. As a consequence, the analysis varies the earned income component of personal income, observed annually, according to the monthly experience in wages and salary income, while holding the other components constant across all months. The net result is a proxy for monthly personal income.

Monthly estimates of county population are obtained by interpolating the annual population estimates, as mentioned above. This approach implicitly assumes that the underlying population evolves at a fairly steady and consistent rate of change over the course of individual years.

The monthly proxy for personal income is divided by estimates of monthly population in order to obtain monthly per capita income, stated in nominal dollars. Finally, monthly per capita income, which serves as a proxy for the true underlying level of income available to individuals and households (which is unobserved within official data) is converted to real terms using the Consumer Price Index for the U.S. economy. In short, per capita income is a main macroeconomic driver within the use-per-customer equations, essentially accounting for leftward and rightward shifts over time in the underlying demand for electricity. The historical experience within Duval County, not Nassau County, is used for model estimation for the Northeast Division.

Q. Is it possible that measures of macroeconomic activity, other than real per capita income at the local level, also explain variation in electricity demand?

A. Yes. The level of monthly employment and proxies for monthly gross product may potentially be constructed and utilized for explaining electricity demand. Along this line of thought, the most relevant issue is one of discovery—finding macroeconomic metrics that are conceptually appropriate and also "fit" in a statistically significant way within the larger set of explanatory variables. Second, even if alternative orthogonal data vectors (time series) are discovered, it is highly likely that, in the context of macroeconomic data, new proxies as constructed, are highly correlated with other macroeconomic time series. As an example, at the national level, personal income and gross domestic product (GDP) move nearly in lock step, demonstrating strikingly high correlation. In brief, it may be of little value to construct gross product metrics (e.g., measures of regional product) with monthly frequency, either in lieu of or in addition to personal income.

Q. Please discuss the development of weather data.

A. *Weather Factors*, including CDDs and HDDs, are drawn from temperature data observed and collected by the National Weather Service (NWS). In the case of the Northeast Division, weather data are culled from the NWS data banks for the Jacksonville Naval Air Station and Fernandina Beach. In the case of the Northwest Division, weather data are drawn from NWS data for the Municipal Airport for the City of Marianna in Jackson County as well as for the City of Tallahassee.

The Company's forecast models utilize weather experience for the period 1999–forward, observed daily. For the four weather stations (Jacksonville Naval Air Station, Fernandina Beach, Municipal Airport for the City of Marianna, and the City of Tallahassee), the historical record of the maximum and minimum temperatures (with daily frequency) includes missing data points, a typical occurrence. As a consequence, it is necessary to fill in the missing data with the weather data for the alternate locations for the Northeast and Northwest Divisions, respectively. The analysis includes an assessment of the correlation and level differences between the weather experiences for the main and alternate locations. The substitute data points, which essentially serve as weather proxies, are adjusted for level differences between the main and substitute locations; the differences are quite small.

The daily temperature data are then converted to CDDs and HDDs using the commonly recognized weather benchmark: 65 degrees Fahrenheit. Alternative CDD and HDD benchmarks have not yet been explored. However, my experience suggests that, for plausible alternative temperature benchmarks, such as 60° F or 70° F, the differences in the estimated effects of CDD and HDD weather metrics on use per customer range from small to vanishingly small. Nonetheless, the possible use of alternative temperature benchmarks is a topic for further exploration.

As with all variables utilized in Step 3, the model's weather metrics (CDDs and HDDs) are converted to monthly frequency. Monthly billed energy reflects energy consumption during the current and previous month. Due to the timing of bills, as determined by bill-cycle practices, a progressively larger share of billed energy for a current month is consumed during the latter days of the previous month, and the early days of the current month. Accordingly, for a current billing month, the daily CDDs and HDDs of the current and previous months (approximately 60 days total) are triangle-weighted, where the central point (greatest weight) is the last day of the previous month and first day of the current month. The monthly normal weather CDDs and HDDs are equal to the average CDDs and HDDs for the respective month, for the period 1999–forward. In the case of the Northeast Division—but less so for the Northwest Division—the analysis has discovered a clear upward trend in temperatures, for both winter and summer periods. This is not unusual; warming trends in weather patterns can be observed in various areas of the North American continent, notwithstanding recent El Nino and La Nina episodes. As a consequence, the observed trends in weather for the Northeast and Northwest Divisions, though small, are incorporated into the projections of normal CDDs and HDDs for the individual months of 2014–2015, with increases in CDDs and decreases in HDDs. Accordingly, the trends in weather are incorporated into the projected billing determinants for the test year, October 2014–September 2015. It goes without saying, the rising long-term trend in temperatures has slowed more recently, and may assume a fairly moderate pace following the rapid pace of rising temperatures over recent decades.

Q: Would you please describe the role of electricity price factors?

A: *Electricity Price Factors* are developed from observed class billing records of the Company's Northeast and Northwest Divisions. Like all normal goods, the demand for electricity services is sensitive to the "own" price of electricity. For the purpose of estimating use per customer, the most relevant—though not exclusive—

price measure is the marginal usage price. Accordingly, estimates of the monthly revenue attributable to customer charges are removed from total monthly revenue, thus isolating revenue attributable to the consumption of electricity. Dividing this volumetric revenue by energy usage obtains estimates for the marginal usage price that, over the sample historical period (2004–2013), is then converted to real terms using the Consumer Price Index for the U.S. economy. This monthly real electricity price incorporates a finite lag process, where the weighting scheme assigns greater weight to near-term months and reduced weight to later months (e.g., the eleventh month) over a twelve-month period.

The procedure just discussed is followed for each customer class (RS, GS, GSD, and GSLD) and both divisions. To summarize, use per customer is a function of the weighted combination of electricity prices over the previous twelve months as well as the several other factors discussed above.

Q. Is electricity demand sensitive to the prices of alternative, substitute forms of energy?

A. Yes, in the very long term, particularly with the rising availability of natural gas supply within areas where, over decades, gas was not previously accessible. It is common for long-run electricity demand studies using panel data to find that electricity demand is sensitive to natural gas prices; essentially, there is a "cross-price" effect. More generally, electricity demand is sensitive to substitute forms of energy in the very long run, under the condition of ready availability of the energy substitutes.

However, energy consumers will take a "whole package view," thus internalizing any incremental capital charges associated with the conversion to alternative energy sources. For example, industrial customers often adopt natural gas-fueled generating technologies for the purpose of on-site power supply, which appears to be currently taking place in Germany. Second, it is to be expected that, in the long term, many residential and commercial customers will select natural gas for space conditioning where natural gas is available.

The Company has recently introduced natural gas within the Northeast Division service territory and, as a consequence, residential and commercial customers may selectively utilize natural gas for space conditioning, prospectively. Also, within the near term, natural gas may be used for power supply at the wholesale level.

At this point, we have not as yet explored the potential inclusion (through imputation) of the prices of alternative energy forms within the use-per-customer models. However, we have incorporated a trace amount of natural gas substitution over electricity within test-year residential sales of the Northeast Division.

Q. Would you please describe the role of other explanatory factors?

A. *Other explanatory factors* are selectively incorporated within the data set analysis, including monthly binary variables, a time trend, and shift factors (which are also represented by binary variables). Shift factors make allowances for abrupt and sometimes transitory changes in dependent variables that are not captured by other explanatory variables incorporated within the model.

Q. Please discuss *Forecast Model Estimation*, Step 3 of the Billing Determinants process.

A. The forecast models are estimated using the data set developed in Step 2. As implied above, the data consists of the "left-hand-side" (LHS) dependent variables, including number of customers, use per customer, and non-coincident demands of the GSD and GSLD classes; and the "right-hand-side" (RHS) explanatory variables consisting of the macroeconomic metrics, weather factors (CDDs and HDDs), the marginal price of electricity, monthly binaries, and other variables such as trend, utilized selectively. The models are estimated in levels, although double-log estimation (for non-binary variables) was also briefly explored.

A levels approach is generally most appropriate—indeed, arguably necessary—when weather factors are included in the RHS data set because electricity consumption is generally linear with respect to weather data over *much of the relevant range* of the variables. As alluded to above, the analysis is conducted with monthly frequency over the years 2004 through 2013, and is based on well known, conventional econometric practices (regression analysis) including appropriate test statistics. In general, the period of estimation should be fairly contemporary but no shorter than ten years, recognizing that relationships among the LHS and RHS variables may evolve prospectively—outside the historical sample period used for estimation.

Q. What are the appropriate criteria for assessing model performance?

A. A primary performance measure is conceptual: forecast models should conform to a plausible explanation of the underlying behavior of electricity demand. Second, the coefficients for the explanatory (RHS) variables should have appropriate directional signs. Third, the magnitude of the coefficients should not stray far from the plausible, as revealed by elasticity calculations. Fourth, overall predictive performance, as technically revealed in the "root mean square error" statistic and visually observed in predicted vs. actual graphs, should be acceptable for the purpose at hand. Fifth, continuous RHS variables preferably should be statistically significant but they may remain within models even if they fail commonly recognized tests of significance. Also, other statistical tests can be drawn into the assessments of models but are not determining.

Q. Please describe key analysis issues and impacts on model performance.

A. The Step 3 analysis, in the form of time series regression models, consists of twenty models. Summary statistics of the estimated equations for number of customers and use per customer, covering the four main classes of the Company's two divisions, are shown in Exhibit RJC-2, pages 1 and 2. Reported performance metrics for each of the estimated equations include *Adjusted* R^2 (the share of variation in the dependent variable explained by the estimated equation, adjusted for degrees of freedom); *RMSE* (root mean square error, a metric for the size of model error); *F Statistic* (*a measure of goodness of fit*); and *# of Observations* (number of data observations over which each equation is estimated). Not reported are the four models for non-coincident demands for the GSD and GSLD classes—two models for each of the Company's two electricity divisions. Not reported but calculated is the increasingly utilized *Akaike Information Criteria* (AIC).

The historical set of data used for model estimation is characterized by random variation within selected data series, an inherent property of small-area forecasting—in this case, the Company's Northeast and Northwest Divisions. Specifically, the Northeast Division serves Amelia Island situated in the northeast corner of Florida and comprises a share of Nassau County. Similarly, the Northwest Division serves areas within Calhoun, Liberty, and Jackson counties in north central Florida. Small area forecasts confront two informational issues. First, observed data regarding historical experience is generally limited or of reduced frequency when compared to that which is available for larger territories such as multiple, integrated county regions or large metropolitan areas. Second, small area forecasting faces random variation, particularly within the underlying number-of-customer and use-per-customer data, where the variation is attributable to unobservable events and thus cannot be easily attributable, through analysis, to causal factors.

Q. Would you please briefly describe the realized performance of the Company's forecast models?

A. Generally speaking, the Company's forecast models are conceptually plausible, obtaining results which are uniformly consistent and reasonable. In the case of the use-per-customer models for the residential class, the macroeconomic metric of household incomes is negatively related to use per customer. This topic requires further explanation, which I will take up later on in this testimony.

The forecast equations in full detail are reported in Minimum Filing Requirement (MFR) Schedule F8 of the Company's filing. As shown, the continuous RHS variables along with the shift factors (captured by binary variables) have the correct signs and provide adequate levels of statistical significance.

Exhibit RJC-2 presents a summary of the performance statistics for the various forecast equations used to provide estimates for the two main dimensions of billing determinants, *number of customers* and *use per customer*. The number-of-customers equations for the Residential and General Service customer classes report Adjusted R^2 results within the 0.90 to 0.95 range, and F Statistics with adequate levels of significance. As expected, the performance metrics for the number-of-customers forecast equations, for the larger business customers, GSD and GSLD, are lower, with Adjusted R^2 results within the 0.62 to 0.70 range, and similarly lower values for the F Statistics. The reduced performance, at least measured in terms of overall fit, is a result of the small sample count for large customers (GSD and GSLD) within each of the Company's two divisions. Note that, for the Northwest Division, the number of customers for the GS and GSD classes is estimated together (GS plus GSLD), and then "shared out" between these two rate classes over time via trend.

The use-per-customer equations for the Residential and General Service classes have Adjusted R^2 values of 0.91 to 0.93, along with adequate F Statistics. For the reasons mentioned above, the GSD and GSLD customer class equations have lower Adjusted

R^2 values, ranging from 0.53 to 0.92, along with correspondingly lower F Statistics. As shown, the use-per-customer models for GSLD in the two divisions have considerable estimation error, a result of the small number of customers taking service under the Company's GSLD tariff. Nonetheless, the forecast results reside well within the realm of the plausible.

Forecast performance can also be gauged through a graphical comparison of the model-based predicted and actual values over the historical sample period, often referred to as *predicted vs. actuals*. These comparisons are presented in Exhibit RJC-3, pages 1–8 and ordered according to the Northeast Division (pages 1–4) and the Northwest Division (pages 5–8), with the number-of-customer and use-per-customer comparisons for each class shown on a single page. Several observations regarding the model performance for the two divisions are as follows:

1) The use-per-customer models appear to capture well the month-by-month and long-term variation in electricity consumption.
2) GSLD use per customer in the Northeast Division is unusually high during 2005 and 2007, with the model-based predicted values for early 2005 understating actual experience (page 4).
3) The number of customers served over the ten-year historical period has considerable random variation, which can be difficult to capture analytically, at least without resorting to extensive use of event variables (binaries).
4) Anomalous customer count experience in the GS and GSD classes of the

Northwest Division is managed with event variables; the models appear to perform well overall.

5) Similarly anomalous customer count experience appears in these two classes (GS and GSD) within the Northeast Division.
6) The small number of customers for the GSLD class, in both the Northeast and Northwest Divisions, inherently make for rather lumpy model performance (pages 4 and 8). The number of GSLD customers, in both the Northeast and Northwest Divisions, is held constant over the forecast test year.

Q. Please explain Step 4, *Determine Test-Year Sales.*

A. Test-year billing determinants (sales) are estimated by applying projections of the forecast drivers within the RHS of the various forecast models. Projections of drivers are, in the case of the binary variables, determined by definition (0, 1). The weather variables, CDDs and HDDs, are based on normal weather and incorporate a slight trend in recognition of steadily warming weather within recent historical years. The real price of electricity is the variable price during each of the months of the final historical year (2013), adjusted downward over time according to the expected rate of inflation (2.20% for 2014 and 2.23% for 2015). (The purchased power price is expected to remain unchanged in real terms.) The test-year macroeconomic drivers including personal income and per capita income, both stated in real terms, reflect the expected near-term change in macroeconomic variables for the small county areas relevant to the Company's Northeast and Northwest Divisions. For the Northeast

Division, projections for the rate of change in real per capita income for the U.S. economy are used as a proxy for Amelia Island (Fernandina Beach) and, when combined with the projected change in population for the area, provide the basis to construct the area proxy for real personal income.

Q. Please explain Step 5, *Incorporate Appropriate Adjustments and Calculate Test-Year Revenues.*

A. As mentioned above, the test-year billing determinants (sales) estimated in Step 4 are adjusted in three ways. First, the estimates of residential use per customer are adjusted downward by 2% in order to capture the expected further declines in use per customer beyond the test year. In view of the ongoing efficiency gains in residential electricity-using technologies, these changes are not only expected but virtually certain, thus constituting known and measurable changes.

Second, we incorporate a comparatively small effect in residential sales resulting from the availability of natural gas for space conditioning and water heating. The working assumption is that 20% of new residential customers in the Northeast Division will select natural gas in lieu of electricity for cooking and water heating. In the case of electric space heating, the assumption is 10%. Using the forecasts of new customers and the assumed shares selecting natural gas (20% for cooking and water heating, 10% for space heating), the residential sales are adjusted according to the residential energy attributable to these end-use applications.

The third adjustment accounts for the sales compression as a consequence to the

Company's filed for change in electricity prices.

Q. You have indicated that further discussion is warranted on two issues: (1) including changes in population trends, and (2) the impact of personal income on electricity use within the residential class. Please elaborate.

A. As mentioned, the historical timeframe over which the forecast models have been estimated is somewhat difficult in view of mid-course changes in key explanatory factors such as regional population. Regarding population, rural areas of the U.S. have been experiencing declines in population for some time, even as the overall U.S. population has been growing and the national economy has been advancing. This history reflects several factors, including, in particular, more robust employment and income opportunities in urban areas for young adults. As shown on Exhibit RJC-4, page 2, the number of U.S. rural counties experiencing declining population during the 2001–2008 period averaged 825, while the number of counties experiencing positive population growth during the same timeframe averaged 779. Florida was exceptional, insofar as typically only one of Florida's rural counties would have a decline in population in any single year during the 2001–2008 period.

By this metric—positive or negative growth in population—the outlook for rural counties has changed markedly for the worse more recently, 2009–2013. For the U.S., and for Florida in particular, a rising number of rural counties appear to be experiencing major, and in some cases chronic, decreases in population. For the U.S., the average number of counties with declining population has risen to 906—an increase of approximately 10% over the previous time period. In Florida, declining population has set in for an average of nine of Florida's sixteen rural counties. While I anticipate that few of Florida's rural counties will experience declining population over the long term, decreasing population for several rural areas will likely continue for a number of forward years. In brief, the abrupt break from rising to declining population for the rural territory served by the Company's Northwest Division is not altogether uncommon. And while the current trends in population may turn positive, it is not likely to reassume the comparatively robust growth of the earlier era, the decade prior to the deep recession of '07–'09.

Q. Please turn to the second issue, personal income and the efficiency of electricity end uses in the residential sector.

A. Historically, increases in real personal income have translated into rising electricity sales, though at a progressively slower rate of change. Evidence demonstrates that the relationship between income and electricity consumption has changed significantly, beginning in the 2006–2008 timeframe. Since that time, rising incomes, overall and on a per capita basis, appear to be negatively related to electricity sales. Exhibit RJC-5, page 1, graphically presents residential energy usage, on a kWh/$1,000 of personal income basis, for the U.S. as whole. Energy use per unit of income rose rapidly through the late 1970s and has subsequently declined by approximately 15%. Residential electricity usage increased, however, as real personal income since the late 1970s increased by approximately 25%.

An equally interesting story regarding the relationship between residential electricity usage and personal income is presented on page 2 of Exhibit RJC-5, subtitled *Residential Electricity Use and Income, stated on a Per Capital Basis*. Here, indexes of per capita electricity use (April and November) and real income are compared. For the years 1990–2006, baseline electricity use on a per capita basis rose by 17% (1.171 for 2006), while real income per capita increased by 38% (1.383 for 2006). Since 2006, however, electricity use per capita has declined by 0.73% annually, while per capita income has risen by 0.43% annually (with the marked slowdown in real income resulting from the deep recession and slow recovery of '09–'12 and continuing). As shown, this experience constitutes a sizable gap between the growth rates for electricity consumption and income: 1.16% and 1.38% during the 2006–2012 and 2008–2012 time periods, respectively. While correlation may not necessarily imply causality, this near-term historical review suggests that the negative relationship between income and electricity usage on a per capita basis, captured in the residential use-per-customer models, is plausible and certainly consistent with the larger experience base of the U.S. overall.

Q. Can you explain how increases in real per capita and personal income translate into declining electricity use per customer within the residential sector?

A. Modern durable consumer goods are increasingly attractive in view of their modern and innovative design features. As discussed further below, rising incomes appear to be associated with a more rapid adoption of modern and much more efficient electricity-using durable goods, including major and minor appliances as well as lighting.

While not conclusive, this reasoning provides an explanation of the negative relationship between real incomes and residential electricity consumption. The end result, under rising incomes, is observable declines in electricity use, stated on both a per capita and a per customer basis.

Q. You have described the workings of rising incomes and declining electricity consumption per capita. Clearly, the apparent advances in electricity-using technologies are central to this analysis. Please elaborate on the attractions of modern end-use equipment within the residential sector and electricity efficiency. If true, this trend could be a major structural factor driving electricity sales.

A. Electricity-using household technologies are undergoing rapid changes, often including major product innovations regarding design, features and controls, and technology. Referred to as durable goods, the most common household energy-consuming technologies include air conditioning, heating, lighting, cooking, water heating, and major appliances, including televisions, washers, and dryers. These end-use technologies have experienced—and are continuing to experience—overall product improvements and dramatic gains in energy efficiency. As mentioned above, modern residential end-use technologies are in demand and have been adopted by consumers fairly rapidly in recent years.

The rate of adoption can be inferred from Indexes of Industrial Production for the Appliance/Electrical Equipment Sectors, when compared to Occupied Housing over recent years. Occupied Housing constitutes the "in-use" housing stock, and can serves as an appropriate basis of comparison. Both sets of data series are presented on Exhibit RJC-5, page 3. As shown, the average rate of production of electricity-using durable goods has declined modestly during the years of the housing slowdown, 2009–2013, when compared to the 2002–2008 period, a time of rapid increases in the U.S. housing stock. In comparison, the average gains in the Occupied Housing metric have slowed by nearly 45% during the more current period (2009–2013), when compared to the 2002–2008 period.

Notwithstanding the effects of the increasing living space of residential dwellings, the net result of product advances within these consumer durable goods is declining individual household energy consumption, as earlier vintage technologies, which constitute the existing capital stock, are replaced with more contemporary units.

Q. Isn't it true that the stock of electricity-using devices is expanding? If true, does not the increased saturation of these devices imply that residential use per customer could rise, as the expanded use of these technologies offsets the reduced energy use for the more conventional applications of residential electricity services that you mention?

A. Without doubt, the smaller electricity-using household appliances/devices cause the electricity usage per residential customer to be higher than otherwise at the national level (and, as I expect, for virtually all regions), as there are only small substitute effects from the major categories of residential electricity consumption. As suggested, the range of electricity-powered devices includes an expanded array of equipment over recent years. These new technologies include audio home entertainment equipment, ceiling fans, desktop and laptop computers, computer monitors, dehumidifiers, DVD players, external power chargers, modems and routers, portable electric spas, pool and pool pumps, security systems, and set-top boxes. Also, we should not forget the expanded array of electricity-using kitchen equipment.

Moreover, studies suggest that household saturation for these smaller-scale devices will likely rise prospectively. And while the annual energy consumption of many of these devices is comparatively small, when taken together the energy usage for this miscellaneous category of energy-consuming technologies is sizable.

Survey-based assessments of the small electricity-using devices provide a more complete view of the underlying markets for these devices and the likely impact on residential electricity consumption. That is, because of the energy-efficiency gains, when stated on a per-device basis, the net overall result is a decline in electricity use per residential customer. Stated annually, the Energy Information Administration's estimates of the changes in electricity use (kWh) between 2011 and 2015 are as follows: for audio home entertainment equipment (from 88 kWh to 83 kWh), for ceiling fans (from 77 to 71), for computers including desktops and laptops (from 280 to 215), for computer monitors (from 99 to 75), for dehumidifiers (from 710 to 620), for DVD players (from 27 to 23), for external power chargers (from 6.5 to 5.6), for modems and routers (from 51 to 44), for portable electric spas (from 2,050 to 2,040), for pool and pool pumps (from 2,460 to 2,060), for security systems (from 45 to 44), and for set-top boxes (from 127 to 107).

To summarize, overall energy consumption for miscellaneous technologies is expected to decline much like the experience for the major residential end-use technologies, despite steady increases in saturation. Indeed, the energy consumption for these smaller electricity-using devices is expected to decline by over 2.5% annually for 2011 through 2015. In brief, the smaller devices as a whole are contributing to the decline in residential use-per-customer electricity demand, despite rising saturation.

Q. Is the rate of adoption of new household technologies related to household income? Also, how does income, through the impact on adoption of contemporary technology, affect energy use per customer? Please discuss.

A. The rate of adoption of new energy-using technologies is positively related to, and driven by, the incomes available to households. While income can be measured in several ways, increases in personal income will give rise to an increase in the rate of adoption of new technologies within the residential sector.

Q. What are the implications for energy use per customer, within the residential class, as a result of long-run increases in household income over time?

A. At least over near-term forward years, rising household incomes, stated in real terms, will likely cause declines in energy use per customer within the residential class. The exception is larger homes; if the average size of homes were to again assume a clear upward trend, it is possible that progressively larger space, stated on a per capita basis, may more than offset the efficiency gains obtained through the adoption of more contemporary-vintage end-use technologies within the residential class.

As alluded to above, residential durable goods, in the form of electricity-using technologies, are undergoing major design improvements, including innovations and expanded features covering a number of dimensions. These improvements make contemporary electricity-using durable goods increasingly attractive. As a consequence, rising household incomes will precipitate increased demand for these good, which will be manifested in a faster rate of obsolescence, as new products are brought into the capital stock of equipment more quickly. Because of the large gains in energy efficiency associated with these modern residential electricity-using technologies, the faster rate of adoption of new products translates into outright reductions in energy use. In brief, electricity use per customer is negatively associated with increasing household income, thus explaining the negative sign on the RHS income variable within the use-per-customer equations for the residential class.

I should also mention that the declining use per customer within the residential class is not unique to FPUC. As presented earlier in my discussion of Exhibit RJC-5, pages 1and 2, the contemporary experience reveals continued declines in residential electricity consumption per unit of personal income. So, even with rising real personal income, stated on a per capita basis, electricity usage per customer will likely continue to decline within near-term years.

Q. Do you anticipate that the negative relationship between residential use per customer and household income will be stationary over an extended future?

A. No. We can expect that, over the long term, the relationship may reverse as energy efficiency gains are exhausted. Second, electric vehicles and robotics will likely assume an increasingly prominent share of use per customer within the residential class. Nonetheless, we can anticipate that the apparent negative relationship may hold over the next few years, though a follow-up review involving the combined experience of several utilities may also be appropriate.

Q. Projected test-year billing determinants translate into revenues for the test year, calculated at current tariff prices. Please discuss.

A. Exhibit RJC-6 presents the Company's test-year revenues, shown monthly by class. Test-year revenues are shown on page 1 for the Northeast Division, and on page 2 for the Northwest Division. Additionally, test-year revenues are shown for the Company's combined electric operations on page 3. The test-year revenues are calculated monthly, obtained by multiplying the billing determinants—number of customers, monthly energy sales, non-coincident demands (GSD, GSLD, and GLSD1), and kVAR (GSLD1)—by the Company's applicable tariff prices.

II. Expected Rate of Inflation

Q. Please provide a summary of your testimony with regard to the expected rate of inflation.

A. With few exceptions, ongoing price inflation has been a feature of contemporary business conditions and over the long term. As a consequence, inflation expectations factor into the decisions of buyers and sellers within markets. It is thus necessary to account for the impact of broadly defined inflation expectations within the costs incurred by Florida Public Utilities Company to provide retail electricity services.

My assessment of inflation expectations covers the years 2014 and 2015, and is based on the combined results of four measures of inflation expectations. These measures include observed *Interest Rate Differentials*, which reveal expectations held by investors, and three surveys, including the *Livingston Survey* of business economists, the University of Michigan/Thompson Reuters *Survey of Consumers*, and the *Survey of Professional Forecasters* conducted by the Philadelphia Federal Reserve Bank.

The assessment leads me to conclude that broad-based inflation expectations held during 2013, for the years 2014 and 2015, were 2.20% and 2.23%, respectively. I recommend that the Florida Public Service Commission adopt these estimates of expected inflation (2.20%, 2.23%) for test-year cost escalation factors in the Company's immediate rate case filing, covering the October 2014–September 2015 test period.

Q. Let's begin by focusing on general inflation. Please describe the notion of

price inflation and the reasons for it.

A. Price inflation (inflation) refers to the change over time in the prices of goods and services. Inflation is expressed in growth rates over time, usually as annual rates of change.

As with virtually all economies, the U.S. macroeconomy continues to experience ongoing price inflation. Broadly defined, price inflation is a common feature of all regions, and permeates all sectors of the U.S. economy over the long term, including electricity services. As alluded to above, expectations of future inflation have become implicitly embedded in the actions of private companies, households, and public institutions.

The causes of price inflation are several. First, both expected and unanticipated increases in the demand for (or decreases in supply of) goods and services across macroeconomies (e.g., that of the U.S. or other sovereign regions) imply upward pressures on prices. Second, changes in the exchange value of sovereign currencies on international currency markets can cause domestic prices to rise or decline.

Third, and importantly, changes in the monetary policy of central banks can often impact price levels across the macroeconomy. This is because the key function of fiat money is the accommodation and facilitation of economic transactions, the purchase/sale of goods and services. Holding other factors constant—in particular, the velocity of money supply and its equivalents, and the demand for asset liquidity—an unanticipated expansion in money supply can cause a corresponding rise in prices, or for prices to rise more rapidly (i.e., for inflation to accelerate). Similarly, a slower rate of change in money supply or the monetary base will correspondingly cause prices to rise more slowly (i.e., a decline in the rate of price inflation). Monetary policy can be implemented by central banks in several ways, including changes in the reserve requirements of commercial banks, changes in the interest rates paid on commercial bank reserves held by central banks, and the purchase and sale of widely held debt securities such as Treasury bonds or other broadly held debt securities (e.g., mortgage-backed securitized debt and commercial paper within wholesale capital markets).

Of the various monetary policy options listed above, the third approach (purchase and sale of debt securities) has been applied extensively by the U.S. Federal Reserve Board in the most recent years. That is, liquidity, in the form of large increases in the monetary base, has been expanded greatly beginning in September 2008, and then extended during early 2011 and 2013. While the expanded monetary base has not precipitated substantial increases in the general price level—because the Federal Reserve pays interest on the accounts held by banks with the Federal Reserve—such policy has caused expected inflation to rise selectively during recent months.

Q. How is inflation measured historically?

A. Inflation is measured as the rate of price change per unit of time. Inflation metrics (indexes of inflation) are based on in-depth monthly and quarterly surveys of prices, and are generally stated as annual rates of change. Inflation indexes, including the consumer price index (CPI) and the producer price index (PPI), are calculated and released monthly by the Bureau of Labor Statistics. The published inflation indexes include price changes for individual wholesale commodities, narrowly defined retail goods or services, and broadly defined sector composites. The CPI metric of inflation is available for both urban consumers and urban wage earners, and for core components. The CPI is also measured for several large, metropolitan areas, including Miami.

The PPI is computed for numerous economic sectors and production stages (commodity, intermediate, and final demand for specific sectors), and for specific commodities, product lines, and services. The PPI includes some 10,000 price series. In addition, price indexes are also estimated by the Bureau of Economic Analysis for the main components of U.S. national income (Gross Domestic Product or GDP), including Personal Consumption Expenditure (PCE) deflators.

Q. Is historical inflation, captured by various price indexes, the same as inflation expectations?

A. By definition, historical inflation refers to observed changes in the various metrics of inflation, such as the indexes described above. In contrast, inflation expectations refer to the estimates of inflation prospectively—the expectations harbored by economic agents (households, business firms, and government entities) regarding the change, or trend, in prices over future periods. Expectations of future inflation are rationally driven by expected levels of demand and supply within specific sectors of the broad macroeconomy, expected money supply, and expected interest rates to the degree that interest rates affect currency exchange rates. Importantly, inflation expectations are influenced by observed historical inflation, and the prices and price changes that parties to transactions actually experience. Price experience covers the gamut of transactions, including, in the case of households, changes in the prices of groceries and apartment rents; in the case of business entities, changes in the invoice prices for rail transport services and components of labor contracts; or in the case of public authorities such as a municipal services department, changes in the prices paid for repair services to reactivate a large water pump used for water supply.

Q. Please describe the methods that you use and recommend for measuring inflation expectations.

A. The task at hand is to estimate expectations of inflation over the near-term future, including the test period, October 2014–September 2015. As mentioned above, the issue of expected inflation is approached by applying two methods: 1) observed interest rate differentials within capital markets, and 2) surveys of expected inflation. These methods are defined as follows:

Interest Rate Differentials: Interest rate/yield differentials between two types of Treasury securities: Nominal and Treasury Inflation-Protected Securities (TIPS). The *Interest Rate Differentials* approach provides estimates of the inflation expectations of investors.

<u>*Survey Methods*</u>:

Projected Rates of Inflation: The consensus view of professional forecasters, as reported in the Philadelphia Federal Reserve Bank's *Survey of Professional Forecasters* (SPF).

Survey of Households: Expectations of future inflation as reported by sampled households included in the *Survey of Consumers* conducted monthly by the Survey Research Center, University of Michigan/Thomson Reuters.

Expectations of Inflation by Economists: Inflation expectations held by academic and business economists, as reported in the *Livingston Survey*, as conducted by the Philadelphia Federal Reserve Bank.

In brief, the approach underlying my assessment of expected inflation draws upon observed market yields on securities of equivalent risks, as well as three surveys. Such an approach is sufficiently broad, capturing the expectations of investors, forecasters, consumers, and business and academic economists.

Q. Would you please elaborate on the *Interest Rate Differentials*- and *Survey*-based methods for measuring inflation expectations?

A. Yes. The *Interest Rate Differentials* method focuses on the inflation expectations of investors, where the term "investors" is interpreted broadly to mean any party that holds, and thus purchases and sells, financial assets, including equities and debt obligations. Transacting parties can thus include individual households, retirement funds, or investment banks trading on behalf of their own accounts.

The market value of financial assets can rise or fall with respect to changes in expected inflation. Some types of assets, such as equities, are less sensitive to expected inflation than others. In the case of debt securities, *yield to maturity* refers to the expected rate of return on the outstanding principle (the securities themselves). Precisely because the face yields on debt securities such as corporate or Treasury bonds are generally held constant at the time of origination, the market value, and thus the net yield, on outstanding debt obligations either decline as expected inflation increases or rise as expected inflation decreases. Changes in market yield account for changes in expected inflation for the investment community as a whole. As a consequence, the *expected real return* on outstanding debt—realized net return after accounting for expected inflation—at a point in time is predominantly, though not exclusively, a function of perceived risks.

This is a natural result of efficient capital market processes, where expected inflation is capitalized within market yields. Debt securities with equivalent risks and terms can be expected to trade at nearly equivalent yields, given expected inflation. This result also means that, for debt obligations of common risk attributes, obligations that fully compensate for (i.e., *are protected from*) inflation should trade at market yields below the yields for obligations with nominal yields, where the difference is approximately equal to expected inflation.

This is the case for selected bond issues of the U.S. Treasury. The U.S. Treasury issues both debt securities with nominal yields, and other bonds that include provisions for inflation compensation. As mentioned, this latter type of Treasury bonds, *Treasury Inflation-Protected Securities*, referred to as TIPS, insulates investors from inflation risk.

Accordingly, this metric for expected inflation, the *Interest Rate Differentials* method, reveals investor expectations by examining the yield differences between nominal and TIPS obligations. For these analyses, nominal and TIPS yield differentials for 5-year U.S. Treasury obligations are calculated monthly for each month of 2013, and then averaged.

Q: Would you please describe the three surveys of inflation expectations listed above?

A. As mentioned, we draw upon the results of three surveys of inflation expectations. Each is described below.

Projections of Inflation are predominantly model-based forecasts of inflation, as reported in the *Survey of Professional Forecasters* (SPF) and organized by the Philadelphia Federal Reserve Bank. This survey dates to 1968 and is carried out quarterly. This survey's results present the consensus view of forecasters, covering the usual macroeconomic metrics of interest but with considerable density—a selection of thirty-two variables altogether. Of particular technical interest is that, for selected variables, SPF reports the dispersion and range of expectations of survey respondents.

Consumer Expectations of Inflation are captured by the *Survey of Consumers,* conducted by the Survey Research Center at the University of Michigan in collaboration with the Thomson Reuters News Service. This survey consists of approximately 500 telephone interviews with randomly selected households, where the question categories include personal finances, business conditions, and purchasing plans. The *Survey of Consumers* was initiated during the late 1940s.

Expectations of Inflation of Economists are based on the survey results gathered and reported semi-annually by the *Livingston Survey*, as mentioned above. This third survey is compiled from the results provided by some fifty respondents, and covers eighteen survey items, such as economic output (real and nominal GDP, corporate profits, business fixed investment, industrial production, retail sales, and auto sales), price inflation (CPI and the PPI), labor markets (unemployment rate, average earnings of wage earners), and capital markets (prime interest rate, 10-year U.S. Treasury bond rate, and the S&P 500 Index).

Q. Please summarize the methods for determining the inflation factor which you describe above.

A. The basis for the inflation factors, for determining cost escalation for the Company's test year, is the annual rates of expected inflation over the period. The overall measure of expected inflation is derived from four estimates involving two methods as I have discussed. The four estimates are expectational in nature: estimates of the expected rate of inflation harbored by four categories of economic actors, including investors, professional forecasters, consumers, and economists.

As discussed above, the first of the two methods, *Interest Rate Differentials*, is the observed interest rate gap between nominal and TIPS yields for U.S. Treasury securities. The second method draws on the expressed views of the identified constituent groups, as gathered through the three formal surveys (*Survey of Professional Forecasters*, *Survey of Consumers* (University of Michigan/Thomson Reuters), and the *Livingston Survey*). The results of these four measures of expected inflation form the basis for the Company's proposed inflation factor, for cost escalation. For this reason, for the purpose of determining future cost escalation, I recommend that the Florida PSC utilize measures for *expectations of inflation* rather than metrics of observed historical inflation.

Q. What are the overall results for the four selected metrics of inflation expectations?

A. Based on the above analyses, I project overall inflation of 2.20% and 2.23% per year for 2014 and 2015, respectively. These results are summarized in the column entitled *Summary Results* in Exhibit RJC-7. This exhibit shows estimates of inflation expectations for each of the four methods: *Nominal-TIPS Yield Differentials (1)*, *Survey of Professional Forecasters (2)*, *Survey of Consumers* (U of M/Thompson Reuters) (3), and the *Livingston Survey (4)*.

Exhibit RJC-7 presents 2013 inflation expectations for 2014 and 2015. Shown from left to right, Exhibit RJC-7 defines the *Forward Year*, details the timeframe for the S*amples of Inflation Expectations* (1^{st} half, 2^{nd} half, or December of 2013), and provides the results for each of methods 1 through 4. The results are summarized for each year in the far right column: expected rates of inflation (during 2013) for 2014 and 2015 are equal to 2.20% and 2.23%, respectively. The average accounts for the four methods. The sample frequency of methods 1 and 3 is higher than for methods 2 and 4.

Q. In your view, is it useful to consider observed historical inflation in order to develop projections of inflation for the near term future?

A. Yes, a useful perspective can be obtained from a review of historical inflation measures, in order to benchmark and assess the reasonableness of projections of inflation. Certainly, historical experience tailors and, to a substantial degree, also drives the expectations of inflation harbored by private companies, households, and other economic actors. In other words, historical inflation experience is implicitly accounted for in expectations of inflation for forward periods.

However, presuming that future price inflation essentially replicates that of historical timeframes, however defined, will likely result in inflation projections that do not align with the expectations held by the economy as a whole. As an example, expectations of inflation measured by interest rate differentials rose by 40 basis points between mid-2012 and March-April 2013, largely as a consequence of changes in the expected impact of the Federal Reserve's monetary policy (i.e., a slowing rate of purchase of financial assets). The expectation of considerably higher inflation, as held by investors, subsequently eased and has remained largely unchanged since early 2013.

Q. Can you please provide examples of expectations of inflation, estimated historically?

A. Historical expectations of inflation refer to expectations held at various timeframes historically. Interest rate differentials between nominal and TIPS yields for the 2003-2013 timeframe have averaged 1.95% and 2.19% for Treasury securities with 5- and 10-year terms, respectively. Similarly, the University of Michigan/Thomson Reuters monthly Survey of Consumers reveals inflation expectations of 3.10% and 3.07% for the same timeframes, 2003–2013 and 2009–2013, respectively. It is important to distinguish between historical samples of expected inflation and actual inflation, measured using various price indexes over historical periods.

Q. Does the rate of inflation within regions of the U.S., such as the Florida Peninsula, vary from the rate of inflation across the U.S?

A. Yes. First of all, it is essential to distinguish between price level and price inflation. Measured in terms of levels, prices across regions can vary greatly. Measured in terms of rates of changes through time, prices across regions appear to evolve in remarkably similar patterns over the long term.

Nonetheless, inflation for specific regions may deviate from the rate of inflation for the U.S. as a whole, over selected timeframes. Regional differences in price inflation are largely attributable to differences in growth in aggregate economic demand for goods and services. A contemporary example is the economic expansion within North Dakota's western region, a result of the vast and sudden expansion of oil and gas production within the Bakken formation. Prices, including labor costs, have risen fast within western North Dakota. Similarly, prices in southeastern Florida, including the Miami Metropolitan Statistical Area (MSA), have outpaced general price inflation for the U.S. during the 2000–2013 period, particularly during 2000–2007. Over recent years, however, it appears that price inflation in this large Florida region has slowed and, prospectively, is likely to closely approximate that of the U.S. In view of the comparative rise in economic activity in South Florida recently, I anticipate that, prospectively, price inflation in South Florida and the U.S. will maintain a similar path. In summary, with few exceptions, projections of inflation expectations for the U.S. as a whole provide an appropriate basis for inflation within various regions of the U.S., including Florida.

Q. Can you please provide a brief summary of the findings of your study of inflation expectations and your recommended inflation factors for cost escalation?

A. Yes. I have conducted an assessment of expected rates of inflation as the basis for estimating the inflation factors, for determining the escalation in costs incurred by Florida Public Utilities Company in providing electricity services during 2014 and 2015. My assessment utilizes the four methods described above. My findings indicate that the appropriate inflation factors for 2014 and 2015 are 2.20% and 2.23%, respectively.

Q. Does this conclude your testimony?

A. It does.

SUMMARY OF HISTORICAL ENERGY SALES, NORTHEAST AND NORTHWEST DIVISIONS

NORTHEAST DIVISION: Class Energy Consumption (MWh)

Class	2008	2009	2010	2011	2012	2013	Test Year
RS	185,850	182,712	201,641	185,895	172,984	171,751	177,658
GS	28,857	27,754	29,507	28,325	28,533	29,292	30,417
GSD	83,844	84,574	86,621	83,877	78,221	75,623	76,462
GSLD	25,665	24,536	26,120	25,109	25,312	27,489	28,617
GSLD1	84,300	64,950	66,580	52,440	58,640	31,440	23,740
OL	1,396	1,392	1,377	1,397	1,378	1,353	1,353
STL	1,127	1,133	1,134	1,031	864	879	851
Total	411,039	387,050	412,980	378,072	365,932	337,827	339,098

NORTHWEST DIVISION: Class Energy Consumption (MWh)

Class	2008	2009	2010	2011	2012	2013	Test Year
RS	143,796	133,594	145,399	132,170	119,996	119,344	126,536
GS	29,298	27,120	28,662	29,238	28,327	27,412	28,989
GSD	89,919	87,224	92,821	85,312	83,243	83,305	83,577
GSLD	57,582	56,901	60,314	62,622	63,279	59,338	58,645
OL	4,181	4,028	3,922	3,894	3,895	4,066	4,074
STL	1,133	1,137	1,147	1,136	1,242	1,253	1,211
Total	325,909	310,004	332,265	314,372	299,983	294,717	303,031

SUMMARY STATISTICS OF ESTIMATED FORECAST EQUATIONS

NORTHEAST DIVISION

Residential Class

RS

# of Customers		Use per Customer	
Performance Measure	Value	Performance Measure	Value
Adjusted R^2	0.94	Adjusted R^2	0.93
Standard Error	56.02	RMSE	71.56
F	398.16	F	97.85
# Obs	108	# Obs	108

Business Classes

GS

# of Customers		Use per Customer	
Performance Measure	Value	Performance Measure	Value
Adjusted R^2	0.95	Adjusted R^2	0.91
RMSE	14.52	RMSE	84.64
F	1079.33	F	80.19
# Obs	120	# Obs	108

GSD

# of Customers		Use per Customer	
Performance Measure	Value	Performance Measure	Value
Adjusted R^2	0.70	Adjusted R^2	0.92
RMSE	6.55	RMSE	1049.90
F	21.02	F	68.87
# Obs	120	# Obs	96

GSLD

# of Customers		Use per Customer	
Performance Measure	Value	Performance Measure	Value
Adjusted R^2	0.62	Adjusted R^2	0.53
RMSE	0.50	RMSE	28143.00
F	15.37	F	8.79
# Obs	117	# Obs	105

SUMMARY STATISTICS OF ESTIMATED FORECAST EQUATIONS

NORTHWEST DIVISION

Residential Class

RS

# of Customers

Performance Measure	Value
Adjusted R^2	0.90
RMSE	34.42
F	313.79
# Obs	72

Use per Customer

Performance Measure	Value
Adjusted R^2	0.92
RMSE	64.65
F	86.29
# Obs	108

Business Classes

GS

# of Customers

Performance Measure	Value
Adjusted R^2	0.95
RMSE	12.77
F	455.21
# Obs	120

Combined regression with GSD

Use per Customer

Performance Measure	Value
Adjusted R^2	0.91
RMSE	58.73
F	71.76
# Obs	108

GSD

# of Customers

Performance Measure	Value
Combined regression with GS	

Use per Customer

Performance Measure	Value
Adjusted R^2	0.84
RMSE	1118.90
F	37.57
# Obs	108

GSLD

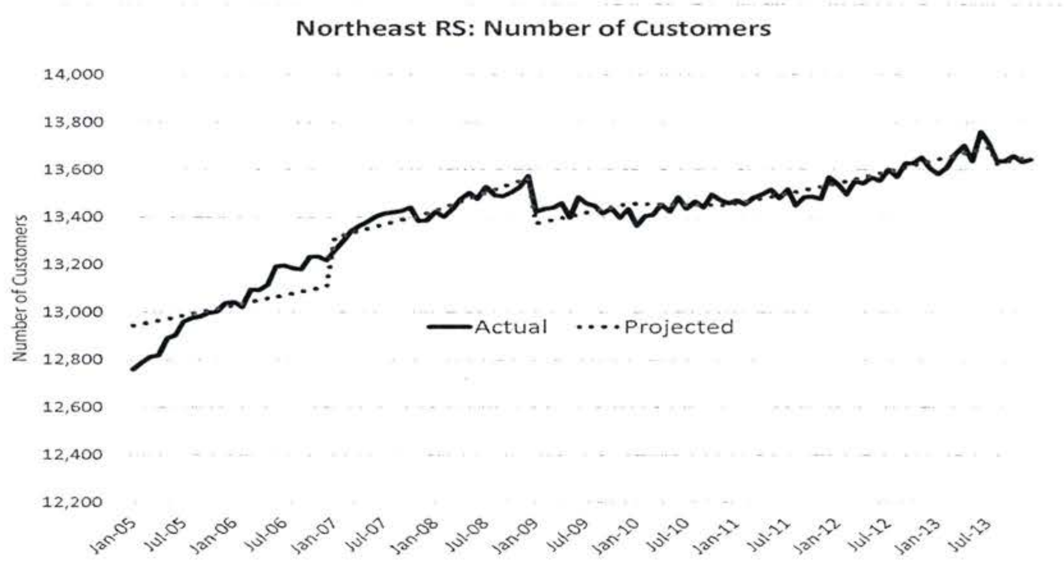
# of Customers

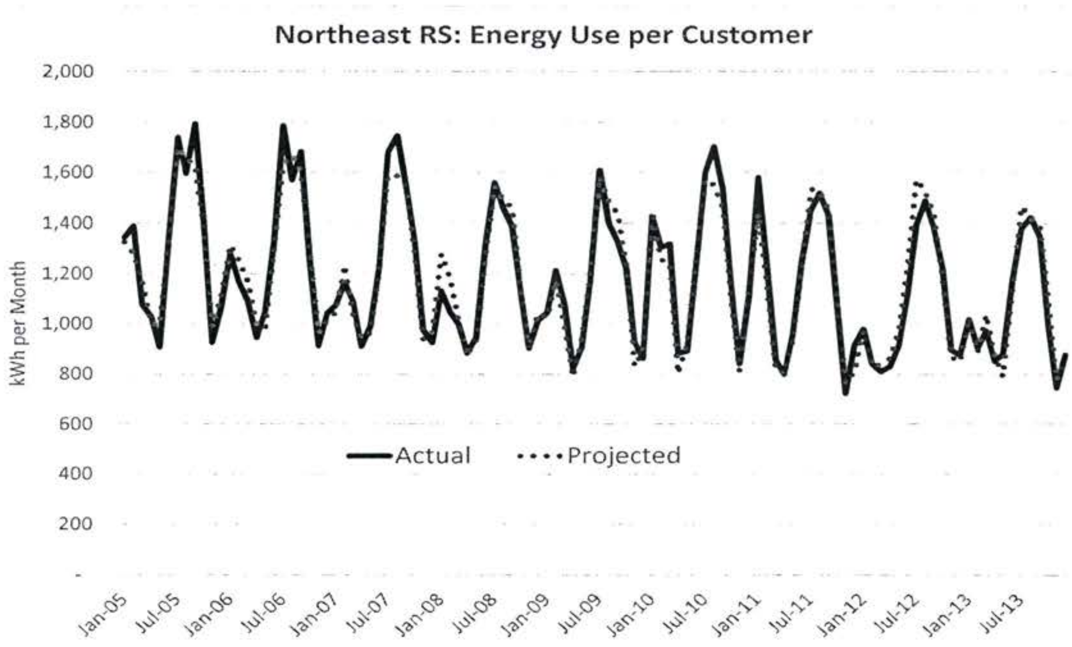
Performance Measure	Value
Adjusted R^2	0.70
RMSE	0.67
F	126.83
# Obs	108

Use per Customer

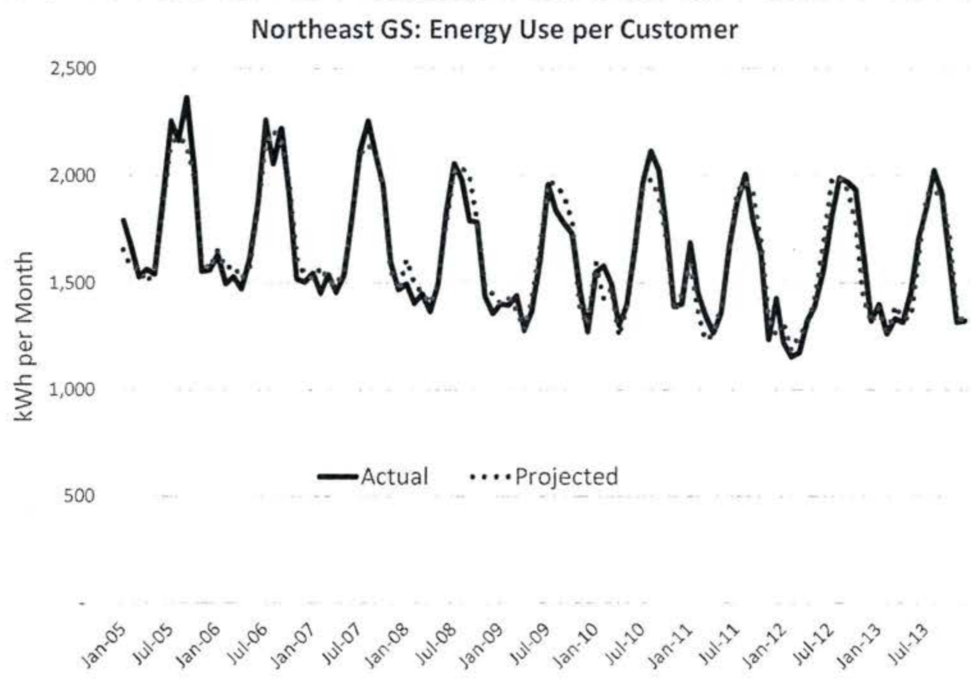
Performance Measure	Value
Adjusted R^2	0.79
RMSE	23353.00
F	25.25
# Obs	96

PREDICTED VS. ACTUALS
RESIDENTIAL CLASS, NORTHEAST DIVISION





PREDICTED VS. ACTUALS
GENERAL SERVICE CLASS, NORTHEAST DIVISION



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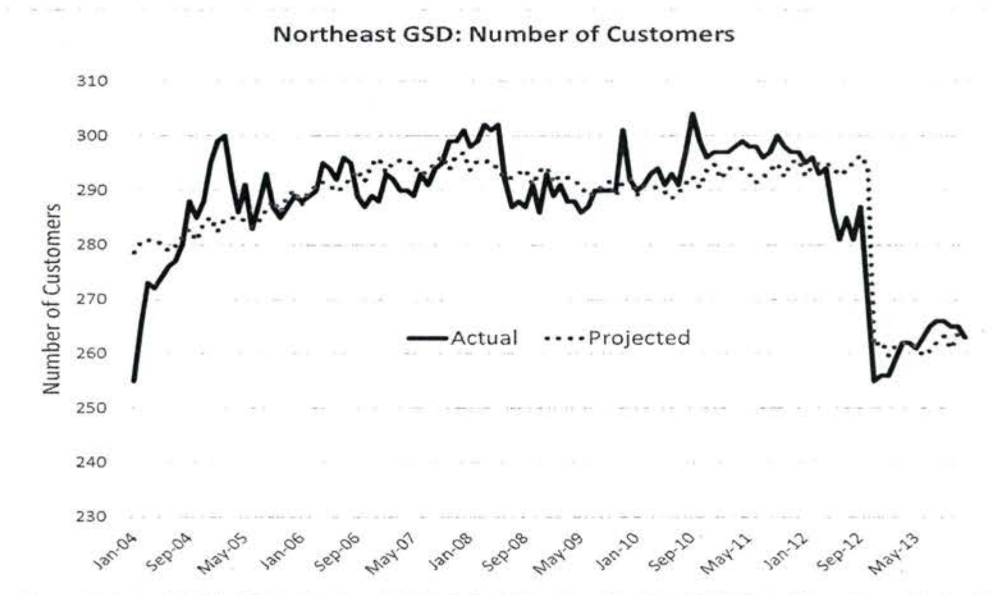
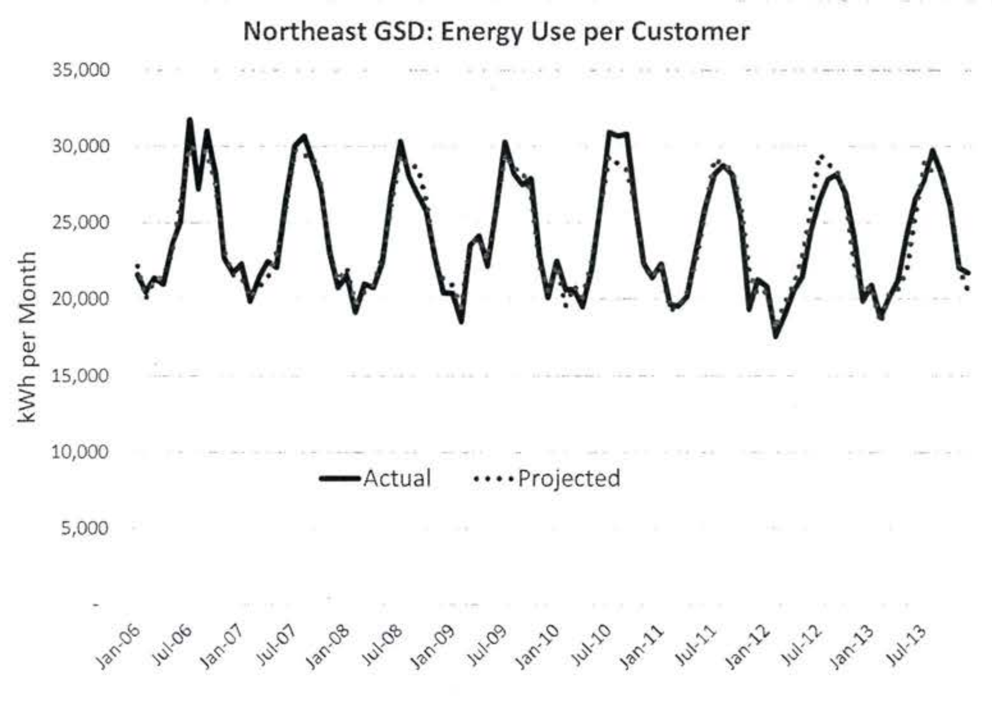
GENERAL SERVICE DEMAND CLASS, NORTHEAST DIVISION





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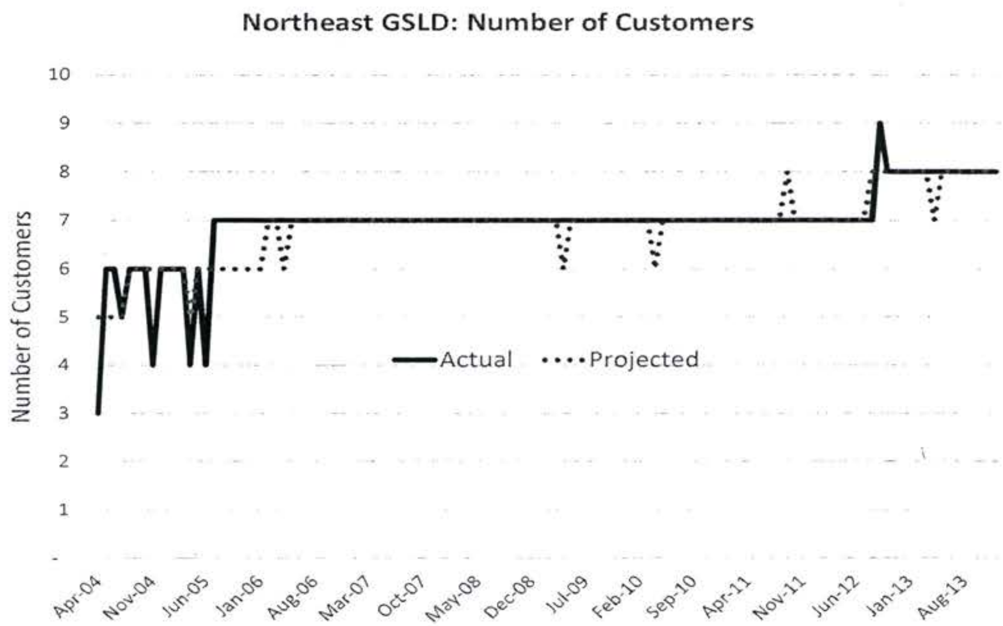
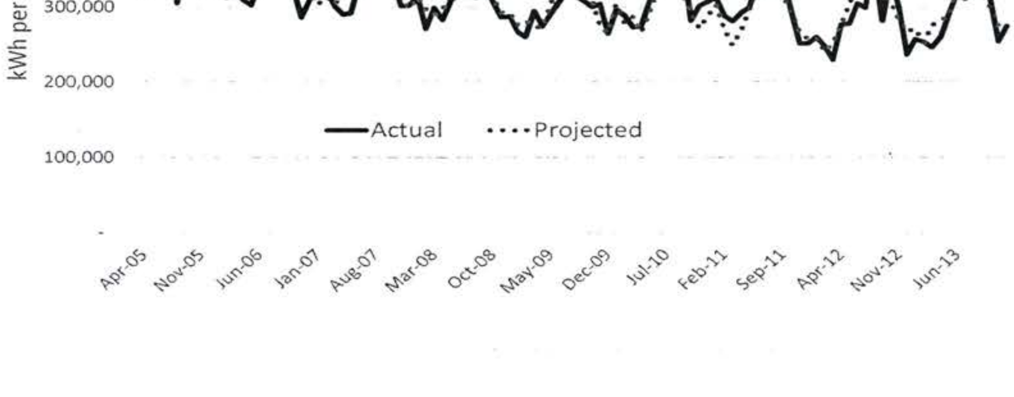
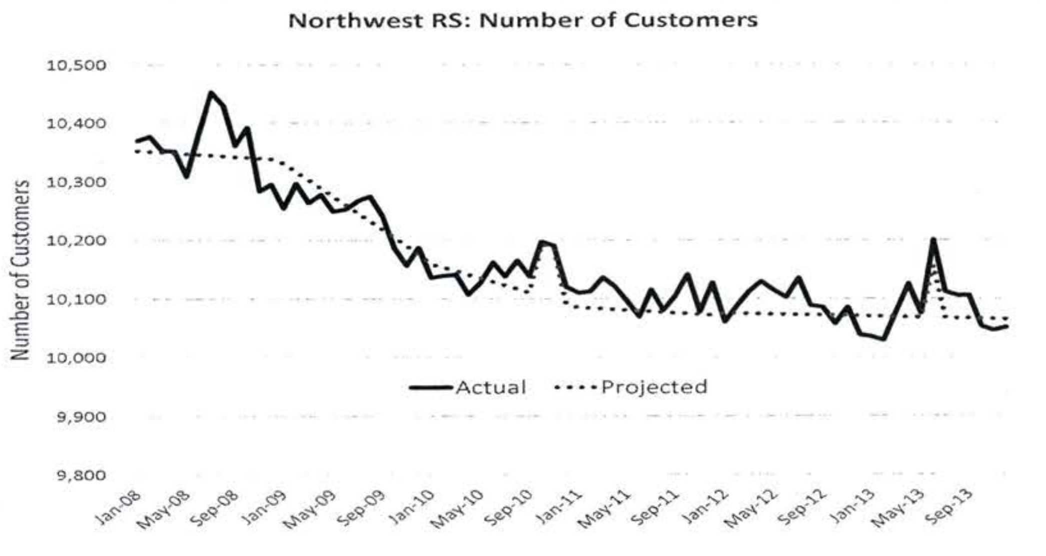
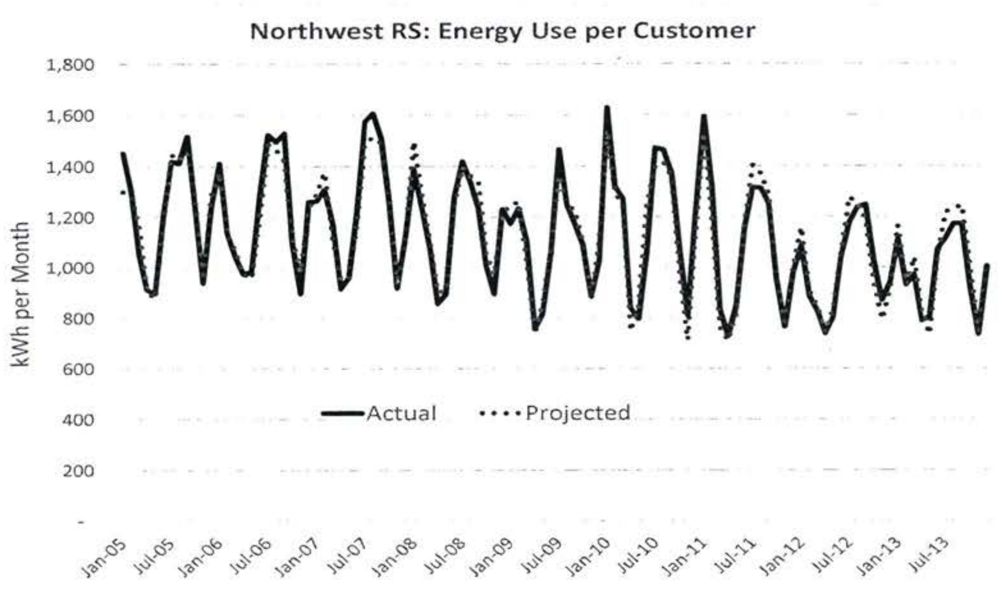
GENERAL SERVICE LARGE DEMAND CLASS, NORTHEAST DIVISION



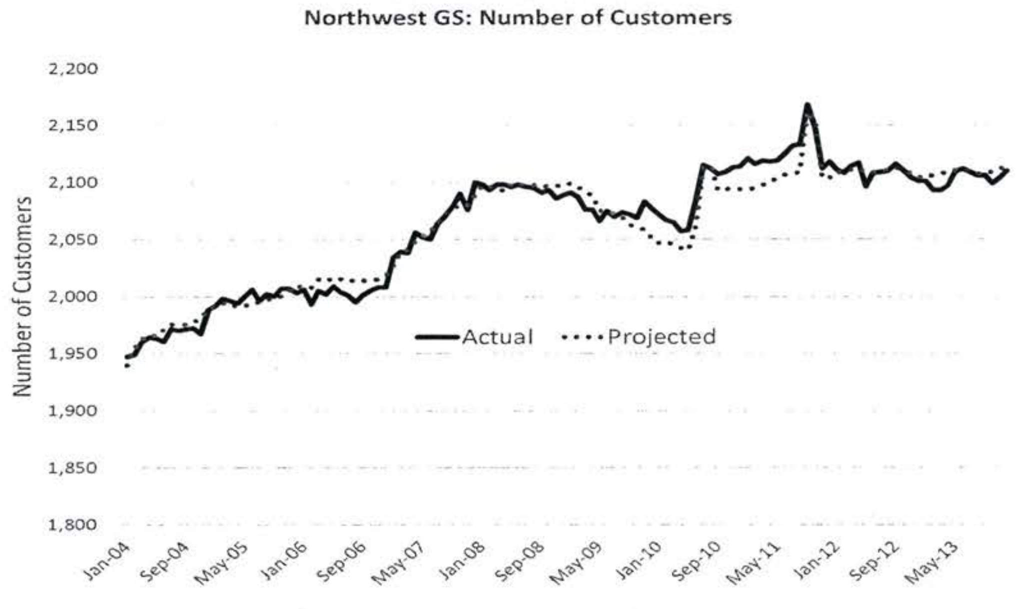


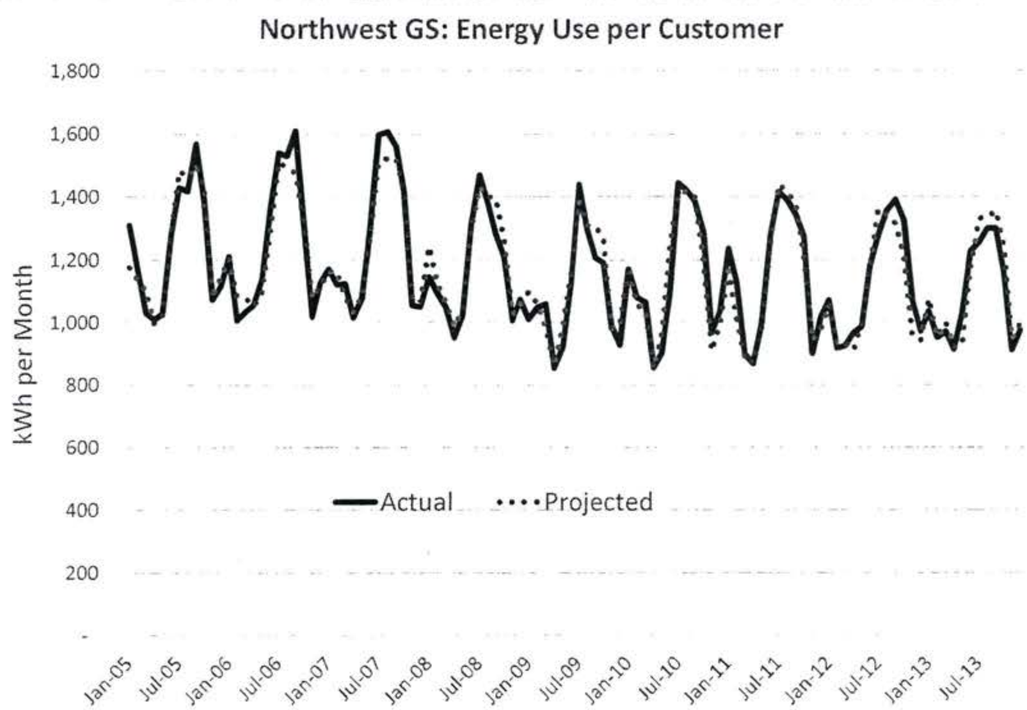
PREDICTED VS. ACTUALS
RESIDENTIAL CLASS, NORTHWEST DIVISION





PREDICTED VS. ACTUALS
GENERAL SERVICE CLASS, NORTHWEST DIVISION





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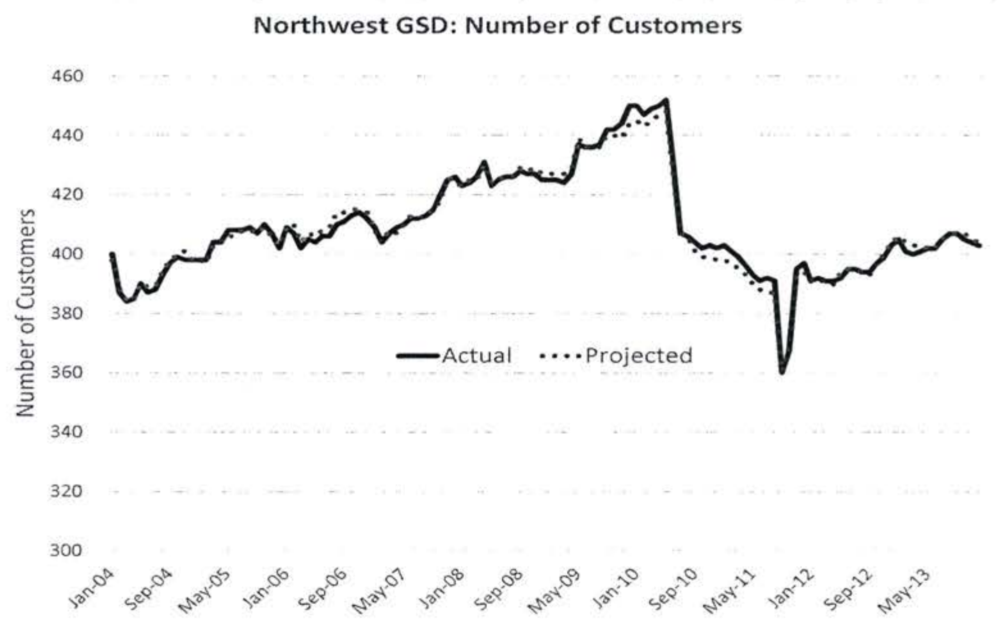
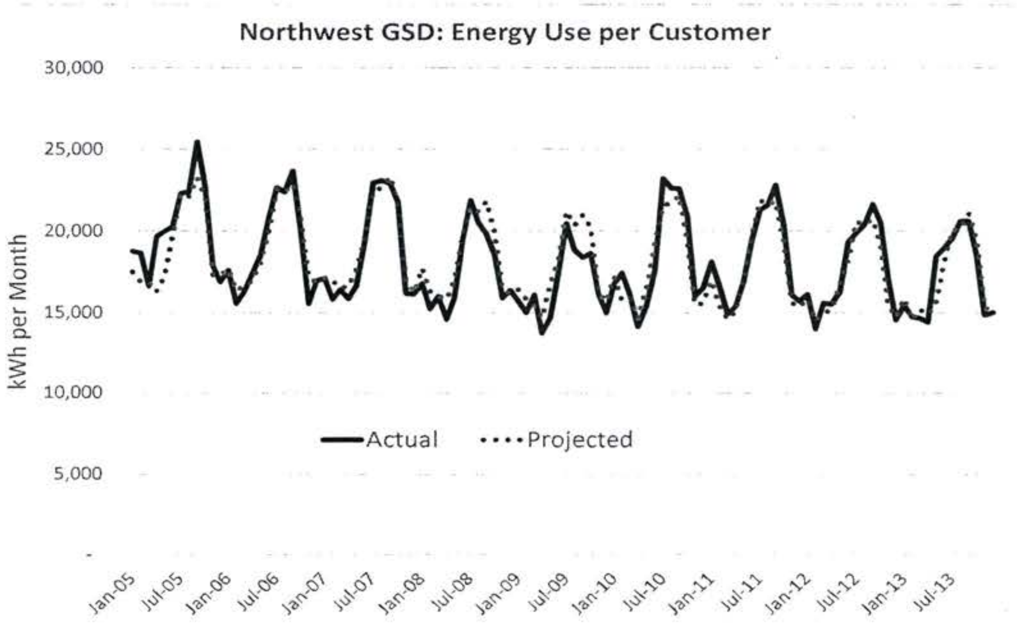
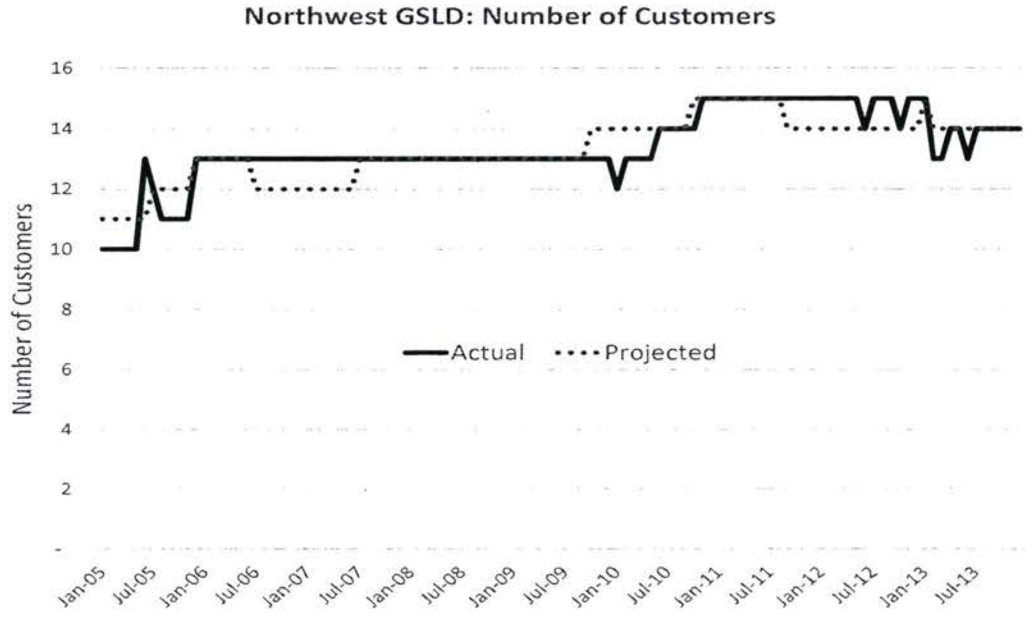
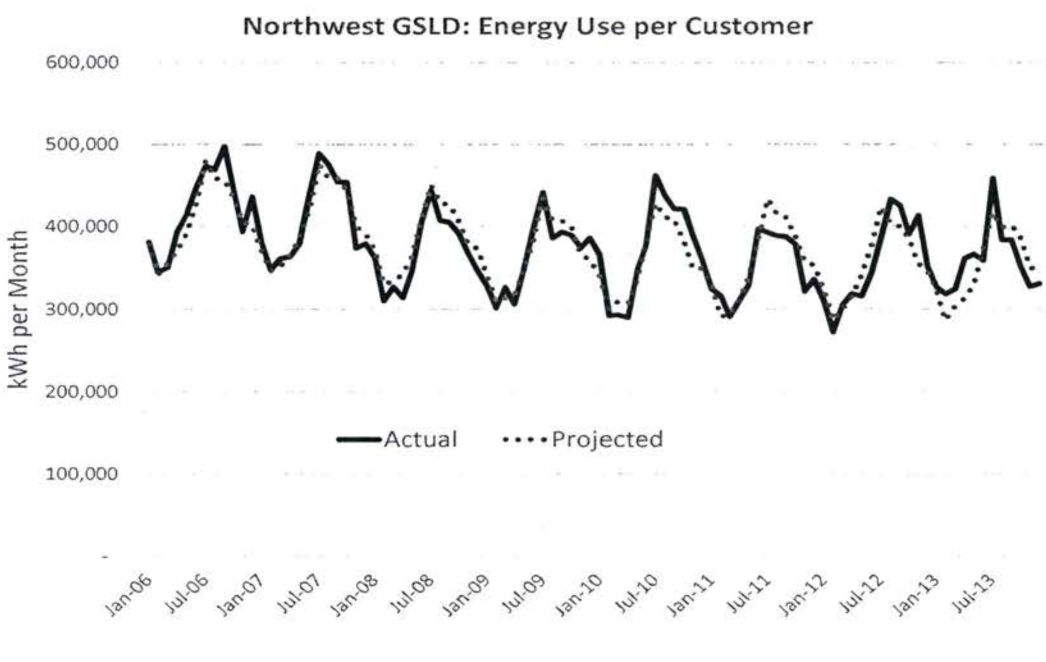
GENERAL SERVICE DEMAND CLASS, NORTHWEST DIVISION



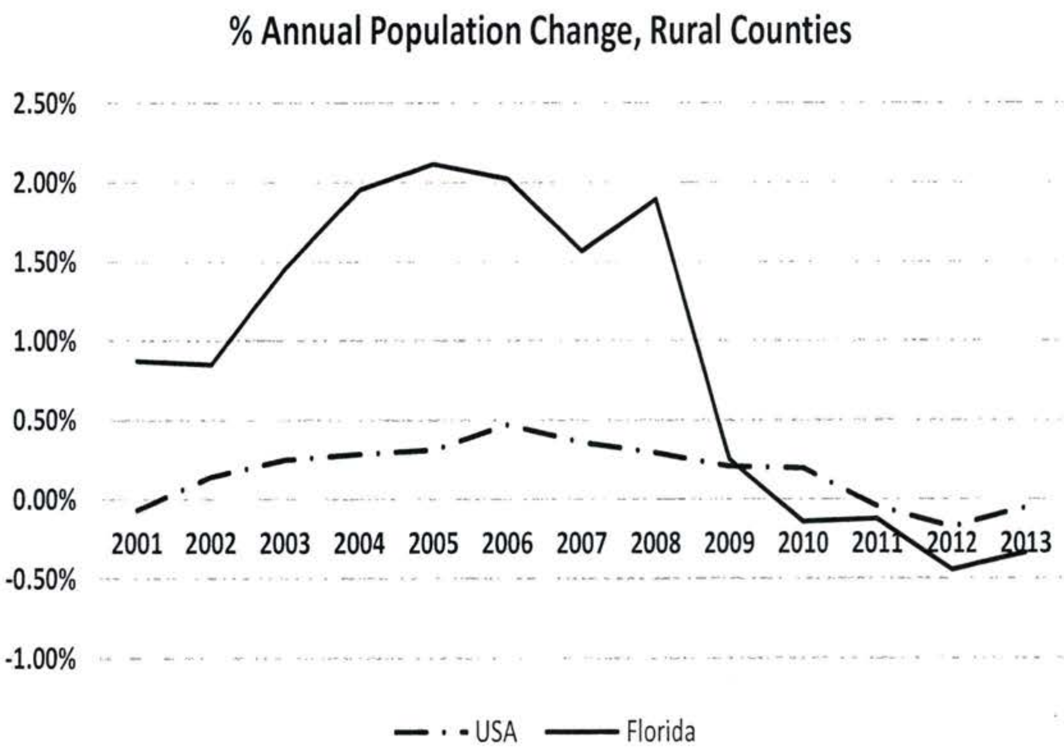


PREDICTED VS. ACTUALS
GENERAL SERVICE LARGE DEMAND CLASS, NORTHWEST DIVISION





CHANGES IN POPULATION OF RURAL COUNTIES, UNITED STATES AND THE STATE OF FLORIDA



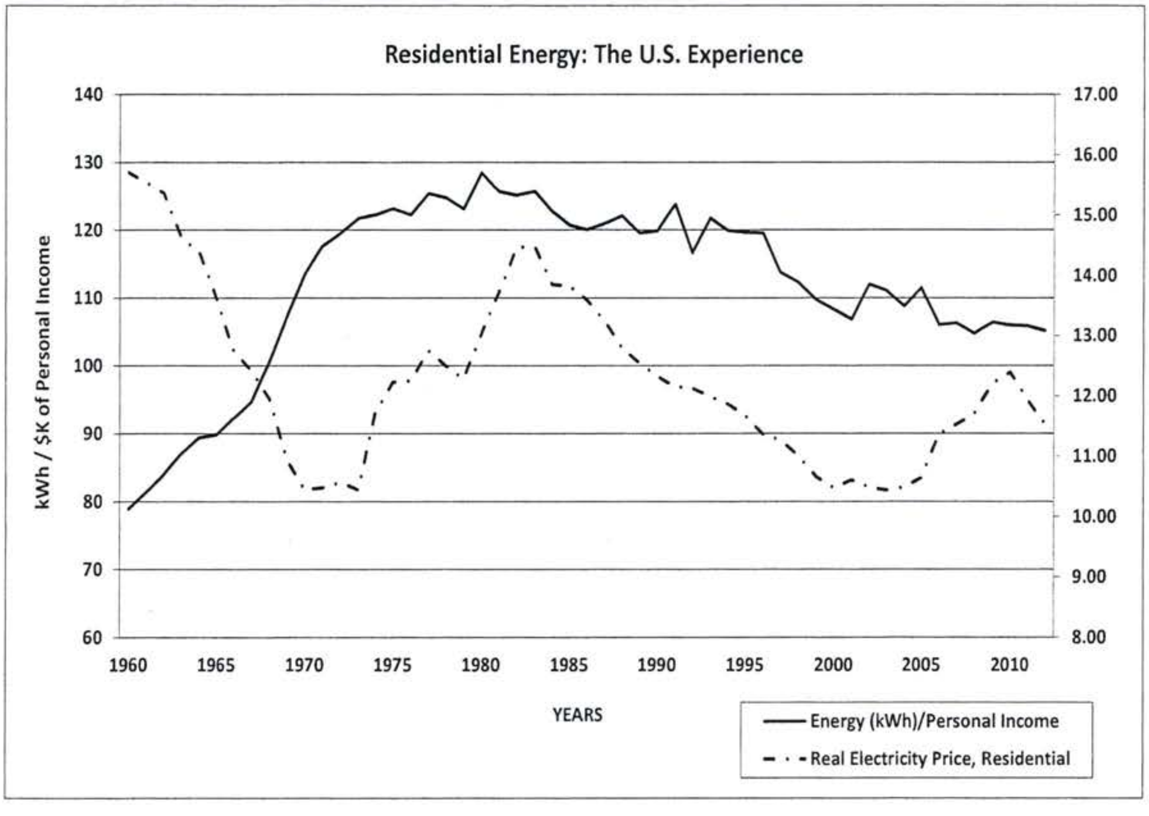
CHANGES IN POPULATION OF RURAL COUNTIES, UNITED STATES AND THE STATE OF FLORIDA

Number of Rural Counties with Positive and Negative Population Growth

UNITED STATES	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Positive Growth	619	726	780	807	794	861	844	804	774	884	633	550	648
Negative Growth	985	878	824	797	810	743	760	800	830	720	971	1054	956
STATE OF FLORIDA													
Positive Growth	14	13	16	16	14	16	16	15	11	8	5	7	5
Negative Growth	2	3	0	0	2	0	0	1	5	8	11	9	11

GLOBAL FACTORS AFFECTING RESIDENTIAL ENERGY USE: REAL PERSONAL INCOME, ELECTRICITY PRICES, AND THE STOCK OF ENERGY-USING TECHNOLOGY

- ENERGY USE PER $K OF PERSONAL INCOME
- REAL ELECTRICITY PRICES OF RESIDENTIAL ENERGY



GLOBAL FACTORS AFFECTING RESIDENTIAL ENERGY USE: REAL PERSONAL INCOME, ELECTRICITY PRICES, AND THE STOCK OF ENERGY-USING TECHNOLOGY

RESIDENTIAL ELECTRICITY USE AND INCOME, STATED ON A PER CAPITA BASIS

	Index: Apr and Nov Electric Use Per Capita	Index of Per Capita Income	Differential Trend: EL Use and Income Per Capita
1990	1.000	1.000	
1991	1.026	0.988	
1992	1.025	1.013	
1993	1.040	1.018	
1994	1.014	1.036	
1995	1.037	1.061	
1996	1.077	1.090	
1997	1.064	1.124	
1998	1.040	1.182	
1999	1.058	1.212	
2000	1.081	1.265	
2001	1.087	1.279	
2002	1.149	1.272	
2003	1.112	1.281	
2004	1.133	1.313	
2005	1.145	1.335	
2006	1.171	1.383	
2007	1.172	1.407	
2008	1.170	1.402	
2009	1.138	1.351	
2010	1.111	1.358	
2011	1.138	1.397	
2012	1.120	1.419	
% Growth, 2006-2012	-0.73%	0.43%	1.16%
% Growth, 2008-2012	-1.08%	0.31%	1.38%

GLOBAL FACTORS AFFECTING RESIDENTIAL ENERGY USE: REAL PERSONAL INCOME, ELECTRICITY PRICES, AND THE STOCK OF ENERGY-USING TECHNOLOGY

CHANGING RATES OF ADOPTION OF MODERN ELECTRICITY END-USE TECHNOLOGIES IN THE RESIDENTIAL SECTOR AS IMPLIED BY INDEXES OF INDUSTRIAL PRODUCTION AND OCCUPIED HOUSING

	Indexes of Industrial Production (IIP)					Changes in Occupied Housing	
Year	Electrical Eq, Appliances	Lighting	Appliances	S. Appliance	L. Appliance	Additions	% Chg
2002	94.24	97.16	96.34	113.98	91.99	1,479	1.43%
2003	90.40	91.38	100.44	107.94	98.66	595	0.57%
2004	91.39	95.20	105.20	106.54	104.89	1,028	0.97%
2005	93.62	96.05	103.85	90.50	106.91	1,643	1.54%
2006	94.90	96.54	101.37	91.42	103.66	1,344	1.24%
2007	100.00	100.00	100.00	100.00	100.00	731	0.67%
2008	97.58	95.90	89.24	94.55	87.97	1,103	1.00%
2009	76.24	75.26	72.40	85.36	69.33	-65	-0.06%
2010	79.93	75.04	71.89	77.37	70.56	516	0.46%
2011	85.92	79.67	70.13	69.70	70.18	1,674	1.50%
2012	89.14	80.25	69.55	70.70	69.25	979	0.86%
2013	91.03	84.45	74.84	72.22	75.35	160	0.14%
Average, 2002-2008	94.59	96.03	99.49	100.70	99.15	1,132	
Average, 2009-2013	84.45	78.93	71.76	75.07	70.93	653	

PROJECTIONS OF TEST-YEAR REVENUES

NORTHEAST DIVISION

(shown in current dollars)

	RS	GS	GSD	GSLD	GSLD1	OL	STL	Total
Oct-14	2,081,096	369,892	748,881	250,632	235,899	42,202	19,928	3,748,530
Nov-14	1,529,561	302,273	647,481	231,473	298,808	41,884	19,997	3,071,479
Dec-14	1,753,161	296,478	612,204	230,840	214,660	42,647	19,878	3,169,868
Jan-15	2,218,966	324,246	633,671	243,022	262,582	41,346	21,288	3,745,120
Feb-15	2,031,539	301,748	577,963	230,631	292,271	41,100	20,992	3,496,246
Mar-15	1,795,554	298,621	603,435	229,264	280,153	41,500	21,279	3,269,808
Apr-15	1,565,473	290,582	613,851	234,746	451,505	41,545	21,074	3,218,776
May-15	1,664,248	309,673	661,706	253,219	312,660	41,512	20,468	3,263,485
Jun-15	2,223,789	365,232	752,918	279,307	341,194	41,649	20,656	4,024,745
Jul-15	2,796,480	421,863	851,066	273,158	303,454	42,688	21,225	4,709,935
Aug-15	2,734,251	428,206	838,144	283,883	272,808	42,105	22,404	4,621,801
Sep-15	2,648,193	418,626	837,661	270,187	437,608	42,451	22,937	4,677,662
Test Year	25,042,312	4,127,438	8,378,984	3,010,362	3,703,602	502,629	252,127	45,017,453

PROJECTIONS OF TEST-YEAR REVENUES

NORTHWEST DIVISION
(shown in current dollars)

	RS	GS	GSD	GSLD	GSLD1	OL	STL	Total
Oct-14	1,411,862	404,076	865,972	553,283		84,292	22,558	3,342,043
Nov-14	1,152,467	326,249	710,764	510,423		84,524	22,709	2,807,136
Dec-14	1,511,887	337,808	699,544	504,321		84,547	22,806	3,160,913
Jan-15	1,896,830	381,170	757,610	482,151		84,320	23,055	3,625,136
Feb-15	1,597,254	346,279	705,961	431,685		84,151	22,629	3,187,959
Mar-15	1,382,514	332,843	698,320	442,975		84,174	22,873	2,963,699
Apr-15	1,148,061	314,581	691,313	457,912		84,543	23,876	2,720,285
May-15	1,198,753	336,654	750,234	492,143		84,326	23,568	2,885,678
Jun-15	1,541,230	399,455	832,938	545,572		84,472	23,319	3,426,986
Jul-15	1,855,846	456,887	932,220	614,109		85,023	23,207	3,967,291
Aug-15	1,830,574	451,763	925,890	584,179		84,297	23,227	3,899,930
Sep-15	1,800,125	451,429	953,880	585,143		84,532	23,309	3,898,417
Test Year	18,327,403	4,539,194	9,524,645	6,203,896		1,013,200	277,135	39,885,473

PROJECTIONS OF TEST-YEAR REVENUES

FLORIDA PUBLIC UTILITIES COMPANY, COMBINED ELECTRIC OPERATIONS
(shown in current dollars)

	RS	GS	GSD	GSLD	GSLD1	OL	STL	Total
Oct-14	3,492,959	773,968	1,614,853	803,915	235,899	126,494	42,486	7,090,573
Nov-14	2,682,028	628,522	1,358,245	741,896	298,808	126,408	42,706	5,878,614
Dec-14	3,265,048	634,286	1,311,748	735,161	214,660	127,194	42,684	6,330,781
Jan-15	4,115,796	705,416	1,391,281	725,172	262,582	125,666	44,344	7,370,256
Feb-15	3,628,793	648,028	1,283,924	662,317	292,271	125,251	43,621	6,684,205
Mar-15	3,178,069	631,465	1,301,755	672,239	280,153	125,674	44,152	6,233,506
Apr-15	2,713,534	605,162	1,305,165	692,658	451,505	126,088	44,949	5,939,061
May-15	2,863,000	646,327	1,411,940	745,362	312,660	125,837	44,037	6,149,164
Jun-15	3,765,020	764,687	1,585,855	824,879	341,194	126,121	43,975	7,451,731
Jul-15	4,652,326	878,750	1,783,287	887,266	303,454	127,711	44,432	8,677,226
Aug-15	4,564,825	879,968	1,764,034	868,062	272,808	126,401	45,632	8,521,731
Sep-15	4,448,319	870,054	1,791,540	855,330	437,608	126,983	46,245	8,576,079
Test Year	43,369,715	8,666,632	17,903,629	9,214,257	3,703,602	1,515,829	529,262	84,902,926

INFLATION EXPECTATIONS
drawn from
OBSERVED INTEREST RATE DIFFERENTIALS
and
SURVEYS OF PROFESSIONAL FORECASTERS, CONSUMERS, AND ECONOMISTS

		METHODS								
					SURVEYS					
		(1)			(2)		(3)	(4)		
	Approximate Time for Sample of Inflation	Nominal - TIPS Yield Differential (%) (shown by term)			Survey of Professional Forecasters		U of M/Thomson Reuters Survey of	Livingston	SUMMARY	
Forward Period	Expectations	5-year	10-year	20-year	CPI (%)	PCE (%)	Consumers (%)	Survey (%)	RESULTS (%)	
	1st Half, 2013	2.09			2.20	2.00	3.17	2.00		
	2nd Half, 2013	1.78			2.00	1.85	3.06			
	Dec, 2013	1.67			2.00	1.90	2.90	1.80		
2014	Across 2013	1.94			2.10	1.93	3.12	1.90	**2.20%**	(for 2014)
	1st Half, 2013	2.09			2.30	2.00	3.06	N/A		
	2nd Half, 2013	1.78			2.20	1.95	2.74			
	Dec, 2013	1.67			2.20	1.90	2.64	2.10		
2015	Across 2013	1.94			2.25	1.98	2.90	2.10	**2.23%**	(for 2015)
Long-Term	1st Half, 2013		2.40	2.54	2.25	2.00		2.50		
	2nd Half, 2013		2.16	2.37	2.10	1.90		2.40		
	Dec, 2013		2.16	2.36	2.10	1.80				
	Across 2013		2.28	2.46	2.18	1.95		2.45	2.24	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 140025-EI

Direct Testimony and Exhibits

Of

Paul R. Moul

Florida Public Utilities Company
Direct Testimony of Paul R. Moul

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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CUC	Chesapeake Utilities Corporation
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
EPACT	National Energy Policy Act
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
FPU	Florida Public Utilities Company
IGF	Internally Generated Funds
LT	Long Term
M&M	Modigliani & Miller
MPL	Minimum pension liability
NAIC	National Association of Insurance Commissioners
OCI	Other Comprehensive Income
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

Docket No. 140025-EI

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

Q. Please describe your educational background and prior experience.

A. I have a Bachelor of Science in Business Administration from Drexel University. I have a long history of experience in this subject area with years of study and testimony before state commissions around the country. My educational background, business experience, and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Florida Public Service Commission (the "Commission") should recognize in the determination of the revenues that Florida Public Utilities Company ("FPU" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into thirteen (13) schedules.

Q. Was this exhibit prepared by you or under your direction or supervision?

A. Yes, it was.

Q. Are you responsible for any of the Company's Minimum Filing Requirements

(MFRs)?

A. Yes. I am sponsoring MFR Number D-1a.

Q. Based upon your analysis, what is your conclusion concerning the appropriate cost of common equity and rate of return for the Company?

A. My conclusion is that the Commission should find that the Company's rate of return on common equity is 11.25%. With this return, I have presented on page 1 of Schedule 1 the weighted average cost of capital of 8.60% that is based on investor-provided capital. In addition, cost of capital components for customer deposits and deferred income taxes also play a role in the rate of return that is applicable to the rate base. The resulting overall cost of capital that will be used to establish rates, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. FPU is a combination electric and natural gas distribution utility. The Company is a wholly-owned subsidiary of Chesapeake Utilities Corporation ("Chesapeake" or "CUC"), which is a diversified energy company that has regulated gas distribution operations in Florida, Delaware, and Maryland, as well as interstate transmission of natural gas on the Delmarva Peninsula and non-regulated propane delivery operations. CUC also has other non-regulated businesses. FPU is a very small electric delivery utility that provides service to approximately 31,066 customers, in two divisions, i.e., Marianna and Fernandina Beach. The Company obtains all of the energy needs for its customers from purchases from JEA, Gulf Power Company, and other marketers. The Company's sales are primarily made to residential and commercial customers, although there are two major industrial customers engaged in the manufacturing of paper that represents approximately 9% of kWh sales.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric utility, such as FPU. In this regard, I relied on four well-recognized measures of the cost of equity: The Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Commission should find that the Company's rate of return on common equity is 11.25%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of eleven (11) electric companies. The criteria that I used to assemble the proxy group will be described later in my testimony. The companies in the electric proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Electric Group?

A. I have applied the market-based models (i.e., DCF, RP, and CAPM) for estimating the cost of equity using the average data for the Electric Group. By employing group average data, rather than individual Company's analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the

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[1]Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

methods/models identified above, and is revealed on page 2 of Schedule 1. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, reliance on a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table, taken from the model results presented on page 2 of Schedule 1, provides a summary of the indicated costs of equity using each of these approaches and recognizing flotation costs.[2]

DCF	9.59%
RP	12.19%
CAPM	10.84%
Comparable Earnings	13.30%
Average	11.48%
Median	11.52%
Mid-point	11.45%

From all measures of the cost of equity, I recommend that the Company's rate of return on common equity be set at 11.25%. The result of the Risk Premium and Comparable Earnings methods indicate that my recommended equity return of 11.25% is conservative. Even the average, median and midpoint of my analyses suggest my recommendation is conservative. To accommodate the Commission's

[2]Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

preference for a range of the cost of equity, I propose a range of 10.25% to 12.25%, which includes the one percentage point band on each side of the midpoint often employed by the Commission. I also believe my recommended cost of equity is appropriate in this case because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events that could occur during the rate effective period.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the risk factors that impact the electric utility industry today.

A. Today, electric utilities face meaningful changes in the fundamentals that affect their operations, but cost of service pricing continues to dominate much of their business profile. On the national level, the passage of the National Energy Policy Act ("EPACT") and the issuance of FERC Order Nos. 888 and 889 and Order No. 2000 initiated sweeping changes that fundamentally altered the structure of the electric utility business.

Q. Will you please elaborate on the risk factors that affect electric utilities today?

A. Yes. Aside from the obligation to serve and the responsibility to maintain reliability, electric utilities are faced with risks associated with demand uncertainty, investment cost uncertainty, and regulatory uncertainty. In addition, the risk of distributed generation will continue to be a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. At the same time, an electric utility retains the obligation to provide reliable delivery service. Utilities must make new investment to provide continuity of quality service, keep rates reasonable, while promoting conservation.

Moreover, regulatory risks include the overall framework of ratesetting, cost allocation, and rate design issues, and the level of return that will be allowed. With increased emphasis on market-determined prices, a new dimension exists in the electric utility business. A pricing structure restricted by regulation or politics diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition.

Q. Are there specific risk issues facing the Company?

A. Yes. Energy deliveries to one commercial and two industrial customers, which represent approximately 42,064,300 of kWh sales, are usually thought to be of higher risk than to residential customers. Success in this segment of the Company's market is subject to the business cycle and pressures from self-generation. Moreover, external factors also can influence deliveries to these customers, which face competitive pressure on their own operations from other facilities outside the utility's service territory.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years (i.e., 2014 through 2018), the Company's total capital expenditures are expected to be approximately \$32.6 million, as described in the testimony of Company witness Mark Cutshaw. These expenditures will represent approximately 52% (\$32.6 million ÷ \$63.0 million) of the net utility plant at December 31, 2013.

A fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital, in all market conditions to meet its needs, and to satisfy investor requirements at reasonable cost. In the situation where significant additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. This is especially important for FPU due to its small size.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared FPU to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Electric Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What criteria did you employ to assemble the Electric Group?

A. The Electric Group companies have the following common characteristics: they are engaged in similar business lines, have publicly-traded common stock, are reported in The Value Line Investment Survey, operate within the southeastern and south central regions of the U.S., and are not currently the target of a merger or acquisition. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company reflects the acquisition price of the target company. The Electric Group includes American Electric Power Company, CenterPoint Energy, Inc., Cleco Corporation, Dominion Resources, Inc., Duke Energy Corp., Entergy Corp., NextEra Energy, Inc., OGE Energy Corp., SCANA Corp., Southern Company, and TECO Energy. The Electric Group members are identified on page 2 of Schedule 3.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. Does FPU have a bond rating from the major credit rating agencies?

A. No. There is no public rating on the debt of FPU. Rather, I have reviewed the credit quality rating of CUC, which provides the basis for the debt component of FPU's rate of return. The CUC's long-term debt carries a designation of "1" from the National Association of Insurance Commissioners ("NAIC"). The NAIC is a non-profit organization that is comprised of the chief insurance regulators of the fifty states, the District of Columbia, and four U.S. territories. Essentially, it is a trade association of insurance regulators much like the National Association of Regulatory Utility Commissioners ("NARUC") is for state economic regulators. NAIC conducts analysis that aids the state regulators in performing their oversight of the insurance companies. As the NAIC has stated:

> The quality of the assets of an insurance company has long been a key concern to state insurance regulators. As the chief public officials charged with the responsibility for monitoring the financial condition of insurers, state regulators must keep a close watch on both the credit quality and the value of those assets.

As noted, the valuation of the assets of insurance companies has been a matter of concern to the NAIC for a very long period of time. The NAIC recognized the need for the standardization of securities valuation across the U.S.

and published its first volume of *Valuation of Securities* in 1908. Later, in 1949, the NAIC set up the Securities Valuation Office ("SVO") to perform analytical valuations of the growing number of securities owned by insurance companies that were acquired through private placement. Privately placed securities owned by insurance companies typically do not have credit quality ratings from Moody's and S&P. The mission of the SVO is to provide state insurance regulators and insurance companies with a uniform source of prices and quality ratings for securities holdings in the portfolios of insurance companies. These prices and quality ratings form what are known as "Association Values" that are used by insurance companies in their Annual Statements filed with state insurance regulators. For many years, the SVO used four bond rating categories: "Yes" (investment grade), "No*" (average quality), "No**" (below average quality), and "No" (in or near default). In September 1986, NAIC Valuation of Securities Task Force began to consider revising its bond rating system that had been used previously to provide a more discriminating set of bond categories. After 2-1/2 years of study, the NAIC established a six-category system that is in use today.

Q. Are NAIC designations comparable to S&P and Moody's?

A. Yes. The NAIC designations provide credit quality ratings for privately placed debt securities that are not rated by Moody's and S&P. The chart below summarizes the alignment between the different ratings by S&P, Moody's and NAIC:

S&P	Moody's	NAIC	
AAA	Aaa	1	
AA+	Aa1	1	
AA	Aa2	1	
AA-	Aa3	1	
A+	A1	1	**Investment**
A	A2	1	**Grade**
A-	A3	1	
BBB+	Baa1	2	
BBB	Baa2	2	
BBB-	Baa3	2	
BB+	Ba1	3	
BB	Ba2	3	
BB-	Ba3	3	
B+	B1	4	**Non-**
B	B2	4	**Investment**
B-	B3	4	**Grade**
CCC	Caa	5	
CC	Ca	5	
C	C	5	
D	D	6	

Q. How do the ratings compare for CUC, the Electric Group, and the S&P Public Utilities?

A. Due to the size of the debt issued by CUC, private placement is the most cost effective way of issuing debt. As noted above, CUC has an NAIC designation of 1, which is equivalent to an A-bond rating and above. For the Electric Group, the average LT issuer rating is Baa1 from Moody's Investors Service ("Moody's") and the average CCR is BBB+ from Standard & Poor's Corporation ("S&P"). The LT issuer rating by Moody's and the CCR designation by S&P focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for FPU, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2008-2012. The analysis covering the years 2011 and 2012 for FPU relate to its electric operations exclusively. The amounts that I used were taken from the Company's FERC Form No. 1 and are not prepared in a rate case format. That is to say, all of the Company's capitalization is represented by proprietary capital for the purpose of the FERC Form No. 1 presentation. Prior years, i.e., 2008, 2009 and 2010, cover both the Company's electric and natural gas distribution operations. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, FPU is very much smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a specific numerical change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for FPU.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings. For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

There are no market ratios available for FPU because the Company's stock is not traded. The five-year average price-earnings multiple for the Electric Group was somewhat below that of the S&P Public Utilities. The five-year average dividend yield was the same for the Electric Group and the S&P Public Utilities. The average market-to-book ratio for the Electric Group was fairly similar to the S&P Public Utilities.

<u>Common Equity Ratio.</u> The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 43.0% for the Electric Group and 45.0% for the S&P Public Utilities. The capital structure for the FPU Electric Division is not meaningful because the CUC capital structure is used for rate of return purposes for FPU.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.873 (5.5% ÷ 6.3%) for FPU, 0.132 (1.6% ÷ 12.1%) for the Electric Group, and 0.104 (1.1% ÷ 10.6%) for the S&P Public Utilities. The earnings variability was much higher for FPU than the Electric Group and the S&P Public Utilities, indicating that the Company has higher risk. Moreover, the Company's generally poor historical earnings performance only adds to its risk.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income taxes).[4] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin. The five-year average operating ratios were 94.6% for FPU, 80.9% for the Electric Group, and 82.3% for the S&P Public Utilities. These comparisons show significantly higher operating risk for FPU as compared to the Electric Group and the S&P Public Utilities. FPU's higher operating ratio can be traced to the significant role that purchased power has on its operations. With a majority of its energy requirements provided by other utilities, the Company must rely upon JEA and Gulf Power Company to provide the majority of the energy

[4]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

needs for its customers. In the hierarchy of claims on the Company's revenues, JEA and Gulf Power Company (i.e., the wholesalers) obtain recovery of their fixed costs prior to the realization of a return for FPU (i.e., the retailer).

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 2.95 times for FPU, 3.23 times for the Electric Group, and 3.12 times for the S&P Public Utilities. The lower interest coverage for FPU can be traced to its lower earnings rate on its common equity. The Company's lower interest coverage adds to its risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for FPU, the Electric Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 126.5% for FPU, 82.3% for the Electric Group, and 91.1% for the S&P Public Utilities. The higher IGF percentage indicates a lower risk factor for FPU.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. As computed by Value Line, the beta coefficient is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk. A comparison of market risk is shown by the Value Line beta of .73 as the average for the Electric Group (see page 2 of Schedule 3), and .75 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation of the Company and the Electric Group.

A. FPU is much smaller than the average size of the Electric Group and its earnings are much more variable. The Company also has a high operating ratio. These factors indicate that the Company has a higher risk profile. The Company's relatively high IGF percentage is an offsetting risk factor. Since several of these risk factors balance out, the cost of equity derived from the Electric Group provides a reasonable basis for measuring the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for FPU.

A. CUC provides all the permanent capital, both debt and equity, for FPU. There is some legacy debt that remains outstanding that was issued prior to FPU's acquisition by CUC. This debt remains outstanding because it is not callable without a make-whole provision to the lender. The Company has determined that it is uneconomic to redeem this debt and make the call premium payment. For this case, CUC's capital structure ratios have been employed for rate of return purposes after assigning the legacy debt directly to FPU. Details of the Company's proposed capital structure are provided in the D-Schedules and are summarized on my Schedule 1.

Q. Why is it appropriate to assign the legacy debt to the Company's weighted average cost of capital with the remainder represented by the Parent Company capitalization?

A. As noted above, there is one series of long-term debt that remains outstanding, which was issued prior to the acquisition of FPU by CUC. When rates were set for the Company prior to the acquisition, this issue of debt was part of the capital structure of FPU for rate of return purposes. As this one issue remains outstanding, it should be included in the Company's capital structure, which is consistent with previous rate cases. The direct assignment of this debt to FPU will avoid having customer rates in other jurisdictions carry the cost of this debt (i.e., Delaware, Maryland, and FERC jurisdictional customers do not benefit from this debt). That is to say, FPU customers have benefited from the assets constructed with the legacy debt, and should continue to carry the cost associated with it. As to the remainder of the Company's capital structure, it should be represented by the relative proportions of the CUC capitalization. This procedure is appropriate because CUC refinanced the other debt previously issued by FPU prior to the acquisition, and CUC will provide all of the new capital needs of FPU on a going forward basis.

Q. Please explain the justification for removing the accumulated Other Comprehensive Income ("OCI") from the capital structure ratios proposed for this case.

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI has its roots in the MPL. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base (i.e., they do not generate or consume any cash). A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. As such, MPL arises from a decline in stock market values and a decline in interest rates, which reduces the value of the trust fund assets and increases the present value calculation of the pension benefit obligation. SFAS 87 requires that the MPL be recognized as a pension expense over future periods, as long as the MPL continues to exist. When stock market improves and when interest rates rise from recent low levels, the MPL will reverse and not impact future pension expense. Hence, the accumulated OCI must be excluded from the common equity.

Q. As shown on Schedule D-1a, the capital structure ratios that the Company proposes for the projected test year 2015 include 41.79% combined legacy debt, long-term debt and short-term debt, and 58.21% common equity based on investor provided capital. Are these ratios reasonable for the Company?

A. Yes. These ratios conform with the Company's capital structure objectives stated on Schedule D-8. Further justification for these ratios rests with the market capitalization capital structure ratios for the Electric Group shown on Schedule 8. Since we are using market-based models (i.e., DCF, RP and CAPM) with data obtained from the Electric Group, then the capital structure ratios derived from the market capitalization of the Electric Group is relevant for comparative purposes. There, the average common equity ratio for the Electric Group is 57.58% based on the market capitalization, which is close to the 58.21% common equity ratio proposed by the Company for ratesetting purposes. Moreover, the Company's common equity ratio is clearly within the range of common equity ratios for the Electric Group based on their market capitalization. Further, the small size of

FPU/CUC requires more conservative financial policies as compared to the Electric Group. The capital structure proposed by the Company will allow it to invest in order to grow its business and take advantage of other opportunities.

COST OF SENIOR CAPITAL

Q. Please explain the cost of debt for FPU.

A. Consistent with the capital structure ratios for the Company, the embedded cost rates of FPU's legacy debt and the cost of CUC's debt must be employed. The determination of the cost of debt is essentially an arithmetic exercise and is provided in the D-Schedules.

Q. The Company has forecast new issues of long-term debt for CUC in September 2014 and in 2015. Are the rates of interest on the new long-term debt financings that the Company has forecast reasonable?

A. Yes. For the September 2014 new issue by CUC, the Company has forecast a rate of 4.50%. For the 2015 issue, the Company has forecast a rate of 5.00%. The Company is proposing a fifteen year term for its proposed new issues of long-term debt. These rates are reasonable based upon the forecast contained in the Blue Chip Financial Forecasts, which I will describe below. According to Blue Chip, the consensus yield on thirty-year Treasury bonds is forecast to be 4.1% for the third quarter of 2014 (see page 2 of Schedule 12). Adding to that yield the interest rate spread of 1.00% related to A-rated public utility bonds that I will describe below, the Blue Chip derived yield would be 5.1% (i.e., 4.1% + 1.0% = 5.1%). This shows that the Company's forecast of 4.5% is reasonable and recognizes that the term for its issue (i.e., 15 years) is shorter than a 30-year issue. Likewise for the 2015 issue, the Blue Chip issue dated December 1, 2013 provides the long-range forecasts of interest rates, which reveals 4.3% yield for 30-year Treasury bonds. Here, the Blue Chip derived yield for A-rated public utility bonds would be 5.3% (4.3% + 1.0% = 5.3%). Again, the Company's forecast is reasonable in light of its shorter 15-year maturity.

Q. Are the projections of future interest rates regarding short-term debt that the Company has proposed in this case reasonable?

A. Yes. The Company has reflected the general trend toward higher interest rates as part of its forecasts in this case. According to the Blue Chip issue that forecasts long-range interest rates, the LIBOR rate that forms the basis for CUC's short-term borrowings are shown below:

Year	LIBOR
2015	0.90%
2016	2.20%
2017	3.30%
2018	4.00%
Average	2.60%

The Company has proposed the use of a four-year average for its short-term borrowings. Therefore, the forecast interest rate for short-term debt would be 3.7% (2.6% + 1.1%), which reflects the 1.10% margin that the Company is required to pay under its short-term credit facility that exceeds LIBOR.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for FPU.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among FPU, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure FPU's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group to arrive at a cost of equity of 11.25%.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model. My DCF results are provided on page 2 of Schedule 1 for the Electric Group. The DCF return is 9.59%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. The monthly dividend yields for the twelve months ended December 2013, are shown on Schedule 5 and capture an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2013, the average dividend yield was 4.01% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 4.04% and 4.03%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 4.04% for the Electric Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Electric Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 5. This adjustment adds eleven basis points to the six-month average historical yield, thus producing, the 4.15% adjusted dividend yield for the Electric Group.

Q. Please explain the underlying factors that influence investor's growth

expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flows stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock. This is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the proxy group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 6 and 7. The historical growth rates were taken from the Value Line publication that provides this data. As shown on Schedule 6, the historical growth of earnings per share was in the range of 3.60% to 5.23% for the Electric Group.

Schedule 7 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 7 for the Electric Group.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 7 indicates that the projected earnings per share growth rates for the Electric Group are 4.99% by IBES/First

Call, 5.27% by Zacks, 5.68% by Morningstar, 5.13% by SNL, and 4.70% by Value Line. The Value Line projections indicate that earnings per share for the Electric Group will grow prospectively at a more rapid rate (i.e., 4.70%) than the dividends per share (i.e., 4.64%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate.

First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts.

Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[5] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Schedule 7, provide a range of average growth rates of 4.70% to 5.68%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts. The stellar performance of the stock market in 2013 points to an improving economy, as it is one of the leading

[5] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

economic indicators compiled by The Conference Board.[6] In fact, the Leading Economic Index, whose financial components include the stock market, has increased for five consecutive months through November 2013. Moreover, "…the strengths among the leading indicators have become more widespread." according to The Conference Board. This improving economic growth argues for a higher DCF growth rate in the future.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Electric Group, those average capital structure ratios are 42.16% long-term debt, 0.26% preferred stock, and 57.58% common equity, as shown on Schedule 8. These capital structure ratios are quite close to the ratios that the Company proposes in this case.

Q. How have you measured the flotation cost allowance as part of the DCF return?

A. The flotation cost adjustment adds 0.19% (9.59% - 9.40%) to the rate of return on common equity for the Electric Group as shown by the calculations provided on page 2 of Schedule 1. In my opinion, this adjustment is reasonable and supported by the analysis of natural gas utility stock issue shown on Schedule 9. On that

[6] The Conference Board U.S. Business Cycle Indicators -The Conference Board Leading Economic Index (LEI) for the U.S. and Related Composite Economic Indexes for November 2013 [Press Release].Retrieved from http://www.conference-board.org/data/bci.cfm dated December 19, 2013.

schedule, I show that the average underwriters' discount and commission and company issuance expenses are 3.3% for the twenty-six issues of common stock shown there for the Electric Group. Since I apply the flotation cost to the entire DCF result, I have utilized a flotation cost adjustment factor of 1.02 on page 2 of Schedule 1.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 12.19% including the adjustment for flotation costs. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, a 5.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the

<u>Blue Chip Financial Forecasts</u> ("<u>Blue Chip</u>") along with the spread in the yields that I describe below. The <u>Blue Chip</u> is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, <u>Blue Chip</u> stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2014, and a yield spread of 1.00%, derived from historical data.

Q. What historical data have you analyzed?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 10. For the twelve months ended December 2013, the average monthly yield on Moody's index of A-rated public utility bonds was 4.48%. For the six and three-month periods ended December 2013, the yields were 4.75% and 4.76%, respectively. During the twelve-months ended December 2013, the range of the yields on A-rated public utility bonds was 4.00% to 4.81%. Page 2 of Schedule 10 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 10, the yields on A-rated public utility bonds have exceeded those on 30-year Treasury bonds by 1.03% on a twelve-month average basis, 0.99% on a six-month average basis, and 0.97% on a the three-month average basis. From these averages, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. **How have you used these data to project the yield on a-rated public utility bonds for the purpose of your Risk Premium analyses?**

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2014	First	4.7%	5.5%	3.9%	1.00%	4.90%
2014	Second	4.8%	5.6%	4.0%	1.00%	5.00%
2014	Third	4.9%	5.7%	4.1%	1.00%	5.10%
2014	Fourth	5.0%	5.8%	4.2%	1.00%	5.20%
2015	First	5.1%	5.9%	4.3%	1.00%	5.30%
2015	Second	5.2%	6.0%	4.4%	1.00%	5.40%

Q. **Are there additional forecasts of interest rates that extend beyond those shown above?**

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2013 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	30-Year	Corporate	
Averages	Treasury	Aaa-rated	Baa-rated
2015-19	5.0%	5.7%	6.7%
2020-24	5.5%	6.3%	7.0%

Given these forecasted interest rates, a 5.50% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity Risk Premium have you determined for this case?

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2014 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 11.

Common Equity Risk Premiums

Low Interest Rates	7.60%
Average Across All Interest Rates	5.79%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.60% when the marginal cost of long-term government bonds was low (i.e., 3.01%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.79% when the average government bond yield was 5.15%. With the recent upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.60% premium related to periods of low interest rates and the 5.79% premium related to average interest rates across all levels.

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CAPITAL ASSET PRICING MODEL

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 10.84% including flotation costs. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially utilized the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.73 for the Electric Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 12, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2013, the average yield on 30-year Treasury bonds was 3.45%. For the six- and three-months ended

December 2013, the yields on 30-year Treasury bonds were 3.76% and 3.79%, respectively. During the twelve-months ended December 2013, the range of the yields on 30-year Treasury bonds was 2.93% to 3.89%.

The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist").

Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. Recently, there has been an increase in Treasury bond yields from their trough that can be attributed to the slow reduction in its bond purchasing program of the FOMC. The term commonly used to describe this reduction in bond purchases is called "tapering." This represents the beginning of the wind-down of the latest quantitative easing by the FOMC, and has put upward pressure on interest rates.

There is a strong indication that the recent increase in interest rates will continue, and indeed there is the significant prospect that further increases in interest rates will occur. As shown on page 2 of Schedule 12, forecasts published by Blue Chip on January 1, 2014 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.9% to 4.4% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 5.0% from 2015 through 2019 and 5.5% from 2020 to 2024. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 4.50% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 12, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 11. On that schedule, the market return was 12.17% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.01% when interest rates were low. As I describe above, interest rates have been trending upward. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 12 the average large common stock returns of 12.11% (12.17% + 12.05% = 24.22% ÷ 2) and the average yield on long-term government bonds of 4.08%

(3.01% + 5.15% = 8.16% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.03% (12.11% - 4.08%) based on historical data, as shown on page 2 of Schedule 12. For the forecast returns, I calculated an 8.68% total market return from the Value Line data and a DCF return of 11.69% for the S&P 500. With the average forecast return of 10.19% (8.68% + 11.69% = 20.37% ÷ 2), I calculated a market premium of 5.69% (10.19% - 4.50%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 6.86% (5.69% + 8.03% = 13.72% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[7] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the

[7]See Fundamentals of Financial Management, Fifth Edition, at 623.

SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the market-based equity capitalization of CUC is $578 million (9,638,230 shares x $60.02 price per share) according to the Value Line the Small & Mid-Cap Survey.[8] For my CAPM analysis, I have adopted the mid-cap adjustment of 1.14%, as revealed on page 3 of Schedule 12.

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all

[8] Value Line report dated December 6, 2013.

companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. [Bluefield Water Works and Improvement Co. v. Public Service Comm'n., 262 U.S. 679, 692 (1923)].

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. How have you implemented the Comparable Earnings Approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definitions for these parameters are provided on page 3 of Schedule 13. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 13, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. And to minimize the effect of a skewed distribution, I removed from the average the returns that were less than 8%. The historical rate of return on book common equity was 13.3% using only the returns that were less than 20% and above 8%, as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.3% also using values less than 20% and above 8%, as provided on page 2 of Schedule 13. Using these data my Comparable Earnings result is 13.30%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding FPU's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable cost of common equity for FPU is

11.25%. My cost of equity recommendation is obtained from a range of results and should be considered reasonable in the context of FPU's risk characteristics as compared to the Electric Group. It is essential that the Commission employ a variety of techniques to measure the FPU's cost of equity because of the limitations/infirmities that are inherent in each method. And equally important, the Commission should recognize the proposed capital structure of FPU in order to provide the Company with a financial profile that will both accommodate the Company's unique risks, as well as provide it with the wherewithal to attract the capital it needs to complete its large construction program.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

Exhibit No. PRM-1

Florida Public Utilities Company

Docket No. 140025-EI

Financial Exhibits

To Accompany

The Direct Testimony

Of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Florida Public Utilities Company
Index of Schedules

Florida Public Utilities Company
Proposed Rate of Return
Projected Test Year, 2015

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-term Debt - FPU Legacy Debt	1.09%	12.74%	0.14%
Long-term Debt - Parent Company	34.21%	4.90%	1.68%
Short-term Debt - Parent Company	6.50%	3.70%	0.24%
Total Debt	41.79%		2.06%
Common Equity - Parent Company	58.21%	11.25%	6.55%
Total	100.00%		8.60%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a 35.000% federal income tax rate (12.13% ÷ 2.06%)	5.90 x
Post-tax coverage of interest expense (8.60% ÷ 2.06%)	4.19 x

Florida Public Utilities Company

Cost of Equity

as of December 31, 2013

Discounted Cash Flow (DCF)				D_1/P_0 [1]	+	g [2]		=	k	x	flot. [3]	=	K
Electric Group				4.15%	+	5.25%		=	9.40%	x	1.02	=	9.59%
Risk Premium (RP)				I [4]	+	RP [5]		=	k	+	flot.	=	K
Electric Group				5.50%	+	6.50%		=	12.00%	+	0.19%	=	12.19%
Capital Asset Pricing Model (CAPM)	Rf [6]	+	β [7]	x (Rm-Rf [8])	+	size [9]		=	k	+	flot.	=	K
Electric Group	4.50%	+	0.73	x (6.86%)	+	1.14%		=	10.65%	+	0.19%	=	10.84%
Comparable Earnings (CE) [10]									*Historical*		*Forecast*		*Average*
Comparable Earnings Group									13.3%		13.3%		13.30%

References
(1) Schedule 05 page 1
(2) Schedule 07 page 1
(3) Schedule 09 page 1
(4) A-rated public utility bond yield comprised of a 4.50% risk-free rate of return (Schedule 12 page 2) and a yield spread of 1.00% (Schedule 10 page 3)
(5) Schedule 11 page 1
(6) Schedule 12 page 2
(7) Schedule 03 page 2
(8) Schedule 12 page 2
(9) Schedule 12 page 3
(10) Schedule 13 page 2

Florida Public Utilities Company
Capitalization and Financial Statistics
2008-2012, Inclusive

	2012	2011	2010	2009	2008	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 44.9	$ 43.3	$ 42.7	$ 97.1	$ 98.4	
Short-Term Debt	$ -	$ -	$ -	$ -	$ 12.7	
Total Capital	$ 44.9	$ 43.3	$ 42.7	$ 97.1	$ 111.2	
						Average
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	0.0%	0.0%	0.0%	19.8%	50.1%	14.0%
Common Equity (1)	100.0%	100.0%	100.0%	80.2%	49.3%	85.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	0.0%	0.0%	0.0%	19.8%	55.8%	15.1%
Common Equity (1)	100.0%	100.0%	100.0%	80.2%	43.6%	84.8%
	100.0%	100.0%	100.0%	100.0%	99.9%	100.0%
Rate of Return on Book Common Equity	3.5%	1.5%	15.5%	3.8%	7.1%	6.3%
Operating Ratio (2)	96.0%	97.5%	90.1%	94.8%	94.6%	94.6%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	3.37 x	1.77 x	5.47 x	2.03 x	2.10 x	2.95 x
Post-tax: All Interest Charges	2.47 x	1.48 x	3.85 x	1.56 x	1.72 x	2.22 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	3.37 x	1.77 x	5.47 x	2.03 x	2.10 x	2.95 x
Post-tax: All Interest Charges	2.47 x	1.48 x	3.85 x	1.56 x	1.72 x	2.22 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Effective Income Tax Rate	38.1%	38.3%	36.3%	45.8%	34.1%	38.5%
Internal Cash Generation/Construction (4)	77.2%	105.4%	211.6%	118.5%	119.6%	126.5%
Gross Cash Flow Interest Coverage (5)	5.35 x	3.39 x	5.73 x	4.89 x	4.36 x	4.74 x

See Page 2 for Notes.

Florida Public Utilities Company
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account..

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

Source of Information: Company provided Financial Statements

Electric Group
Capitalization and Financial Statistics [1]
2008-2012, Inclusive

	2012	2011	2010 (Millions of Dollars)	2009	2008	
Amount of Capital Employed						
Permanent Capital	$ 26,267.6	$ 21,883.7	$ 20,615.4	$ 19,820.8	$ 18,250.0	
Short-Term Debt	$ 793.1	$ 629.7	$ 532.0	$ 430.0	$ 731.5	
Total Capital	$ 27,060.7	$ 22,513.4	$ 21,147.4	$ 20,250.8	$ 18,981.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	16 x	13 x	12 x	13 x	14 x	14 x
Market/Book Ratio	176.9%	167.5%	155.2%	146.8%	175.8%	164.4%
Dividend Yield	4.1%	4.4%	4.8%	5.2%	4.5%	4.6%
Dividend Payout Ratio	68.3%	57.7%	59.0%	66.8%	63.2%	63.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	55.4%	55.0%	55.7%	57.3%	57.7%	56.2%
Preferred Stock	0.9%	0.9%	0.7%	0.6%	0.7%	0.8%
Common Equity [2]	43.7%	44.2%	43.5%	42.1%	41.5%	43.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	56.7%	56.2%	56.9%	58.2%	59.1%	57.4%
Preferred Stock	0.9%	0.9%	0.7%	0.6%	0.7%	0.7%
Common Equity [2]	42.4%	43.0%	42.4%	41.3%	40.2%	41.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.6%	12.8%	13.7%	11.4%	13.1%	12.1%
Operating Ratio [3]	78.5%	79.7%	79.9%	82.2%	84.2%	80.9%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.11 x	3.72 x	3.75 x	3.05 x	3.24 x	3.37 x
Post-tax: All Interest Charges	2.48 x	2.87 x	2.78 x	2.43 x	2.55 x	2.62 x
Overall Coverage: All Int. & Pfd. Div.	2.44 x	2.84 x	2.75 x	2.40 x	2.51 x	2.59 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.01 x	3.61 x	3.65 x	2.83 x	3.06 x	3.23 x
Post-tax: All Interest Charges	2.38 x	2.76 x	2.68 x	2.21 x	2.37 x	2.48 x
Overall Coverage: All Int. & Pfd. Div.	2.35 x	2.73 x	2.65 x	2.18 x	2.33 x	2.45 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.0%	5.9%	6.6%	15.5%	12.3%	9.5%
Effective Income Tax Rate	29.6%	31.0%	34.8%	29.5%	30.9%	31.2%
Internal Cash Generation/Construction [5]	81.5%	88.7%	89.6%	81.3%	70.3%	82.3%
Gross Cash Flow/ Avg. Total Debt [6]	21.3%	21.9%	22.1%	20.8%	20.7%	21.4%
Gross Cash Flow Interest Coverage [7]	5.88 x	5.19 x	4.86 x	4.70 x	4.43 x	5.01 x
Common Dividend Coverage [8]	4.15 x	4.23 x	4.37 x	4.25 x	4.09 x	4.22 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:

The Electric Group includes companies reported in the basic service of The Value Line Investment Survey, within the group "Electric Utility Industry," their stock is traded on the New York Stock Exchange, they operate within the southeastern and south central regions as defined by the Federal Energy Regulatory Commission's Bureau of Power, and they are not currently the target of a merger or acquisition.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
AEP	American Electric Power	Baa1	BBB	NYSE	B	0.70
CNP	CenterPoint Energy	Baa1	A-	NYSE	B	0.80
CNL	Cleco Corp.	Baa2	BBB+	NYSE	B	0.70
D	Dominion Resources, Inc.	A3	A-	NYSE	B+	0.70
DUK	Duke Energy Corp.	A3	BBB+	NYSE	B	0.65
ETR	Entergy Corp.	Baa2	BBB	NYSE	A	0.70
NEE	NextEra Energy, Inc.	A2	A-	NYSE	A	0.70
OGE	OGE Energy Corp.	A2	A-	NYSE	A-	0.85
SCG	SCANA Corp.	Baa2	BBB+	NYSE	A-	0.70
SO	Southern Company	A3	A	NYSE	A-	0.55
TE	TECO Energy, Inc.	A3	BBB+	NYSE	B	0.95
	Average	Baa1	BBB+		B+	0.73

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2008-2012, Inclusive

	2012	2011	2010 (Millions of Dollars)	2009	2008	
Amount of Capital Employed						
Permanent Capital	$ 21,620.0	$ 18,840.8	$ 17,587.3	$ 16,618.6	$ 15,620.1	
Short-Term Debt	$ 648.9	$ 531.4	$ 435.4	$ 415.0	$ 803.5	
Total Capital	$ 22,268.9	$ 19,372.2	$ 18,022.7	$ 17,033.6	$ 16,423.6	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	15 x	15 x	14 x	14 x	15 x
Market/Book Ratio	164.0%	155.2%	142.8%	137.1%	174.9%	154.8%
Dividend Yield	4.1%	4.4%	4.8%	5.2%	4.3%	4.6%
Dividend Payout Ratio	70.3%	64.7%	72.0%	72.2%	61.9%	68.2%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.9%	52.9%	53.4%	54.2%	54.3%	53.5%
Preferred Stock	1.6%	1.3%	1.3%	1.5%	1.7%	1.5%
Common Equity [2]	45.5%	45.8%	45.3%	44.3%	44.0%	45.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.5%	54.5%	54.7%	55.6%	57.1%	55.3%
Preferred Stock	1.6%	1.3%	1.3%	1.4%	1.6%	1.4%
Common Equity [2]	44.0%	44.3%	44.0%	43.0%	41.3%	43.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.2%	10.5%	10.8%	10.1%	12.2%	10.6%
Operating Ratio [3]	81.3%	81.4%	81.6%	83.0%	84.1%	82.3%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.94 x	3.35 x	3.34 x	3.06 x	3.39 x	3.22 x
Post-tax: All Interest Charges	2.35 x	2.59 x	2.52 x	2.36 x	2.57 x	2.48 x
Overall Coverage: All Int. & Pfd. Div.	2.32 x	2.57 x	2.50 x	2.33 x	2.53 x	2.45 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.85 x	3.25 x	3.25 x	2.96 x	3.28 x	3.12 x
Post-tax: All Interest Charges	2.25 x	2.49 x	2.43 x	2.26 x	2.46 x	2.38 x
Overall Coverage: All Int. & Pfd. Div.	2.22 x	2.47 x	2.41 x	2.22 x	2.42 x	2.35 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	5.7%	6.6%	7.8%	7.7%	7.0%
Effective Income Tax Rate	26.2%	36.8%	34.3%	31.8%	33.8%	32.6%
Internal Cash Generation/Construction [5]	75.0%	89.4%	108.0%	100.0%	83.1%	91.1%
Gross Cash Flow/ Avg. Total Debt [6]	21.9%	23.2%	23.9%	22.5%	22.6%	22.8%
Gross Cash Flow Interest Coverage [7]	5.37 x	5.12 x	5.09 x	4.85 x	4.75 x	5.04 x
Common Dividend Coverage [8]	4.31 x	4.58 x	4.88 x	4.73 x	4.95 x	4.69 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating (1) Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AGL Resources Inc.	GAS	A3	BBB+	NYSE	A	0.75
Ameren Corporation	AEE	Baa2	BBB	NYSE	B	0.80
American Electric Power	AEP	Baa2	BBB	NYSE	B	0.70
CMS Energy	CMS	Baa1	BBB	NYSE	B	0.75
CenterPoint Energy	CNP	Baa2	BBB+	NYSE	B	0.80
Consolidated Edison	ED	A3	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A3	BBB+	NYSE	B+	0.75
Dominion Resources	D	A3	A-	NYSE	B+	0.65
Duke Energy	DUK	A3	BBB+	NYSE	B	0.60
Edison Int'l	EIX	A3	BBB+	NYSE	B	0.75
Entergy Corp.	ETR	Baa2	BBB	NYSE	A+	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.15
Exelon Corp.	EXC	A3	BBB	NYSE	B+	0.80
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	A-	0.80
Integrys Energy Group	TEG	A2	A-	NYSE	B	0.90
NextEra Energy Inc.	NEE	A2	A-	NYSE	A	0.75
NiSource Inc.	NI	Baa2	BBB-	NYSE	B	0.85
Northeast Utilities	NU	Baa2	A-	NYSE	B	0.70
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	NR	1.10
ONEOK, Inc.	OKE	Baa2	BBB	NYSE	NR	0.95
PEPCO Holdings, Inc.	POM	Baa2	BBB+	NYSE	B	0.75
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.55
PPL Corp.	PPL	Baa2	BBB	NYSE	B+	0.65
Pinnacle West Capital	PNW	Baa1	BBB+	NYSE	B	0.70
Public Serv. Enterprise Inc.	PEG	A3	BBB	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.65
Sempra Energy	SRE	A2	A	NYSE	A-	0.80
Southern Co.	SO	A3	A	NYSE	A-	0.55
TECO Energy	TE	A3	BBB+	NYSE	B	0.85
Wisconsin Energy Corp.	WEC	A2	A-	NYSE	A	0.65
Xcel Energy Inc	XEL	A3	A-	NYSE	B+	0.65
Average for S&P Utilities		Baa1	BBB+		A	0.75

Note: (1) Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending December 2013

Company	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	12-Month Average	6-Month Average	3-Month Average
American Electric Power Co., Inc.	4.19%	4.03%	3.89%	3.84%	4.29%	4.40%	4.27%	4.59%	4.55%	4.31%	4.26%	4.31%			
CenterPoint Energy, Inc. (CNP)-N	4.10%	3.88%	3.48%	3.39%	3.59%	3.55%	3.37%	3.63%	3.48%	3.40%	3.55%	3.60%			
Cleco Corporation (CNL)-NYSE	3.18%	3.05%	2.88%	2.95%	3.19%	3.14%	3.01%	3.22%	3.25%	3.15%	3.18%	3.13%			
Dominion Resources, Inc. (D)-NY	4.19%	4.02%	3.88%	3.67%	4.02%	3.97%	3.82%	3.85%	3.61%	3.55%	3.50%	3.49%			
Duke Energy Corporation (DUK)-I	4.49%	4.43%	4.24%	4.10%	4.58%	4.56%	4.44%	4.77%	4.70%	4.39%	4.47%	4.55%			
Entergy Corporation (ETR)-NYSE	5.20%	5.35%	5.28%	4.71%	4.83%	4.80%	4.98%	5.27%	5.30%	5.19%	5.38%	5.29%			
NextEra Energy, Inc. (NEE)-NYSI	3.69%	3.67%	3.41%	3.24%	3.49%	3.25%	3.06%	3.29%	3.30%	3.13%	3.12%	3.09%			
OGE Energy Corp. (OGE)-NYSE	2.85%	2.90%	2.40%	2.31%	2.47%	2.46%	2.24%	2.38%	2.33%	2.27%	2.44%	2.48%			
SCANA Corp. (SCG)-NYSE	4.37%	4.20%	3.98%	3.77%	4.06%	4.15%	3.93%	4.26%	4.42%	4.38%	4.35%	4.34%			
Southern Company (SO)-NYSE	4.48%	4.37%	4.21%	4.25%	4.64%	4.63%	4.58%	4.90%	4.97%	5.02%	5.02%	4.98%			
TECO Energy, Inc. (TE)-NYSE	5.01%	5.11%	4.97%	4.64%	5.01%	5.16%	5.04%	5.34%	5.36%	5.18%	5.18%	5.14%			
Average	4.16%	4.09%	3.87%	3.72%	4.02%	4.01%	3.89%	4.14%	4.12%	4.00%	4.04%	4.04%	4.01%	4.04%	4.03%

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://finance.yahoo.com/
SNL Financial LC

Forward-looking Dividend Yield				
1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	
	4.04%	1.026250	4.14%	
Discrete	D_0/P_0	Adj.	D_1/P_0	
	4.04%	1.032603	4.17%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	
	1.0096%	1.012874	4.15%	
Average			4.15%	
Growth rate			5.25%	
K			9.40%	

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates

Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Electric Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
American Electric Power	1.00%	2.00%	4.00%	-3.00%	4.50%	2.50%	0.50%	-
CenterPoint Energy	3.00%	-1.50%	7.00%	-4.50%	13.50%	-4.00%	2.00%	-
Cleco Corp.	13.00%	5.50%	4.50%	2.50%	9.00%	8.00%	14.50%	6.00%
Dominion Resources, Inc.	7.00%	5.00%	7.00%	4.50%	3.50%	2.50%	2.50%	2.50%
Duke Energy Corp.	4.50%	-	18.00%	-	-1.00%	-	-	-
Entergy Corp.	5.50%	7.50%	7.50%	10.00%	5.00%	4.00%	10.50%	9.50%
NextEra Energy	10.00%	8.50%	7.50%	7.00%	8.50%	8.00%	7.00%	6.50%
OGE Energy Corp.	7.50%	8.00%	2.50%	1.50%	8.50%	7.00%	9.00%	5.50%
SCANA Corp.	2.50%	3.00%	3.00%	5.00%	4.50%	4.00%	-0.50%	3.00%
Southern Company	3.00%	3.50%	4.00%	3.50%	5.50%	4.50%	3.50%	3.00%
TECO Energy, Inc.	0.50%	-5.50%	2.00%	-4.50%	4.00%	-2.50%	1.50%	-3.50%
Average	5.23%	3.60%	6.09%	2.20%	5.95%	3.40%	5.05%	4.06%

Source of Information: Value Line Investment Survey, November 22, 2013 and December 20, 2013

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

					Value Line				
Electric Group	I/B/E/S First Call	Zacks	Morningstar	SNL	Earnings Per Share	Dividends Per Share	Book Value Per Share	Cash Flow Per Share	Percent Retained to Common Equity
American Electric Power	3.99%	4.00%	8.30%	4.60%	5.50%	4.00%	4.00%	4.00%	4.50%
CenterPoint Energy	4.50%	5.30%	3.00%	5.00%	6.00%	4.00%	5.00%	4.50%	6.00%
Cleco Corp.	8.00%	8.00%	-	-	5.50%	10.00%	5.00%	5.00%	4.50%
Dominion Resources, Inc.	7.18%	6.00%	6.60%	6.70%	5.00%	5.50%	4.50%	5.50%	4.50%
Duke Energy Corp.	3.83%	3.70%	5.90%	3.00%	4.00%	2.00%	3.50%	4.00%	3.00%
Entergy Corp.	NMF	NA	NMF	NMF	NMF	0.50%	3.00%	1.00%	3.50%
NextEra Energy	6.62%	6.20%	7.40%	6.80%	5.50%	8.50%	6.50%	5.00%	5.50%
OGE Energy Corp.	5.00%	6.00%	6.10%	7.00%	5.00%	8.50%	7.00%	2.00%	5.50%
SCANA Corp.	4.20%	4.40%	4.90%	5.10%	4.50%	2.50%	5.50%	3.00%	4.50%
Southern Company	3.83%	4.10%	3.50%	3.00%	3.00%	3.50%	4.00%	3.50%	3.00%
TECO Energy, Inc.	2.72%	5.00%	5.40%	5.00%	3.00%	2.00%	1.50%	3.00%	4.00%
Average	4.99%	5.27%	5.68%	5.13%	4.70%	4.64%	4.50%	3.68%	4.41%

Source of Information : Yahoo Finance, December 17, 2013
Zacks, December 17, 2013
Morningstar, December 17, 2013
SNL, December 17, 2013
Value Line Investment Survey, November 22, 2013 and December 20, 2013

Electric Group□
Market Capitalization

	American Electric Power Co(NYSE:AEP)	CenterPoint Energy, Inc. (NYSE:CNP)	Cleco Corporation (NYSE:CNL)	Dominion Resources, Inc (NYSE:D)	Duke Energy Corporation (NYSE:DUK)	Entergy Corporation (NYSE:ETR)	NextEra Energy, Inc. (NYSE:NEE)	OGE Energy Corporation (NYSE:OGE)	SCANA Corporation (NYSE:SCG)	The Southern Company (NYSE:SO)	TECO Energy, Inc. (NYSE:TE)	Average
Fiscal Year	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	12/31/13	
Capitalization at Fair Values												
Debt(D)	19,672,000	8,670,000	1,420,048	22,473,000	42,592,000	12,439,785	28,612,000	2,652,600	5,916,300	21,530,000	3,184,100	15,378,348
Preferred(P)	0	0	0	261,000	0	116,760	0	0	0	1,131,000	0	137,160
Equity(E)	22,798,714	9,944,220	2,818,390	37,584,890	48,721,060	11,285,524	37,244,700	6,725,760	6,617,130	36,476,903	3,746,252	20,360,322
Total	42,470,714	18,614,220	4,238,438	60,318,890	91,313,060	23,842,069	65,856,700	9,378,360	12,533,430	59,137,903	6,930,352	35,875,831
Capital Structure Ratios												
Debt(D)	46.32%	46.58%	33.50%	37.26%	46.64%	52.18%	43.45%	28.28%	47.20%	36.41%	45.94%	42.16%
Preferred(P)	0.00%	0.00%	0.00%	0.43%	0.00%	0.49%	0.00%	0.00%	0.00%	1.91%	0.00%	0.26%
Equity(E)	53.68%	53.42%	66.50%	62.31%	53.36%	47.33%	56.55%	71.72%	52.80%	61.68%	54.06%	57.58%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock												
Issued	508,113.964	429,000.000	61,047.006	581,000.000	706,000.000	254,752.788	435,000.000	198,500.000	141,000.000	893,000.000	217,300.000	
Treasury	20,336.592	0.000	592.486	0.000	0.000	76,381.936	0.000	100.000	0.000	5,700.000	0.000	
Outstanding	487,777.372	429,000.000	60,454.520	581,000.000	706,000.000	178,370.852	435,000.000	198,400.000	141,000.000	887,300.000	217,300.000	
Market Price	$ 46.74	$ 23.18	$ 46.62	$ 64.69	$ 69.01	$ 63.27	$ 85.62	$ 33.90	$ 46.93	$ 41.11	$ 17.24	

Analysis of Public Offerings of Common Stock
Years 2007-2011

	Vectren Corp	Energy East	Empire District	ITC Holdings	Ottertail Corp	OGE Energy	PNM Resources	IDACORP	Progress Energy
Date of Offering	2/22/2007	3/21/2007	12/6/2007	1/18/2008	9/19/2008	11/20/2008	11/27/2008	12/5/2008	1/7/2009
No. of shares offered (000)	4,600	9,000	3,000	5,583	4,500	2,500	3,417	3,000	12,500
Dollar amt. of offering ($000)	$ 130,318	$ 218,250	$ 69,000	$ 291,669	$ 135,000	$ 62,500	$ 27,883	$ 85,215	$ 468,750
Price to public	$ 28.330	$ 24.250	$ 23.000	$ 50.150	$ 30.000	$ 25.000	$ 8.160	$ 28.405	$ 37.500
Underwriter's discounts and commission	$ 0.990	$ 0.728	$ 0.997	$ 2.131	$ 1.088	$ 1.500	$ -	$ 0.284	$ 1.125
Gross Proceeds	$ 27.340	$ 23.522	$ 22.003	$ 48.019	$ 28.913	$ 23.500	$ 8.160	$ 28.121	$ 36.375
Estimated company issuance expenses	$ 0.092	$ 0.018	$ 0.083	$ 0.161	$ 0.089	$ 0.058	N/A	N/A	$ 0.024
Net proceeds to company per share	$ 27.248	$ 23.504	$ 21.920	$ 47.858	$ 28.824	$ 23.442	$ 8.160	$ 28.121	$ 36.375
Underwriter's discount as a percent of offering pric	3.5%	3.0%	4.3%	4.2%	3.6%	6.0%	0.0%	1.0%	3.0%
Issuance expense as a percent of offering pric	0.3%	0.1%	0.4%	0.3%	0.3%	0.2%	N/A	N/A	0.1%
Total Issuance and selling expense as as a percent of offering pric	3.8%	3.1%	4.7%	4.5%	3.9%	6.2%	0.0%	1.0%	3.1%

	Portland General Elec	Northeast Utilities	American Elec Power	Great Plains Energy	UNITIL	UIL Holdings	Ameren	CenterPoint	Consolidated Edison
Date of Offering	3/5/2009	3/16/2009	4/1/2009	5/12/2009	5/20/2009	5/20/2009	9/9/2009	9/10/2009	11/20/2009
No. of shares offered (000)	10,850	16,500	60,000	10,000	2,400	4,000	19,000	21,000	5,000
Dollar amt. of offering ($000)	$ 152,985	$ 333,300	$1,470,000	$ 140,000	$ 48,000	$ 84,000	$ 479,750	$ 252,000	$ 213,150
Price to public	$ 14.100	$ 20.200	$ 24.500	$ 14.000	$ 20.000	$ 21.000	$ 25.250	$ 12.000	$ 42.630
Underwriter's discounts and commission	$ 0.494	$ 0.657	$ 0.735	$ 0.490	$ 1.050	$ 1.050	$ 0.758	$ 0.420	$ -
Gross Proceeds	$ 13.606	$ 19.543	$ 23.765	$ 13.510	$ 18.950	$ 19.950	$ 24.492	$ 11.580	$ 42.630
Estimated company issuance expenses	$ 0.035	$ 0.020	$ 0.007	$ 0.030	N/A	$ 0.081	$ 0.024	N/A	$ 0.100
Net proceeds to company per share	$ 13.606	$ 19.543	$ 23.765	$ 13.510	$ 18.950	$ 19.950	$ 24.492	$ 11.580	$ 42.630
Underwriter's discount as a percent of offering pric	3.5%	3.3%	3.0%	3.5%	5.3%	5.0%	3.0%	3.5%	0.0%
Issuance expense as a percent of offering pric	0.2%	0.1%	0.0%	0.2%	N/A	0.4%	0.1%	N/A	0.2%
Total Issuance and selling expense as as a percent of offering pric	3.7%	3.4%	3.0%	3.7%	5.3%	5.4%	3.1%	3.5%	0.2%

	Pinnacle West Capital Corp.	SCANA Corp.	CenterPoint	UIL Holdings	Consolidated Edison	Westar	Black hills Corp.	PPL Corp.	AVERAGE
Date of Offering	4/8/2010	5/11/2010	6/9/2010	9/16/2010	9/27/2010	11/4/2010	11/10/2010	2/11/2011	
No. of shares offered (000)	6,000	7,150	22,000	17,700	6,300	7,500	4,000	80,000	
Dollar amt. of offering ($000)	$ 228,000	$ 264,550	$ 283,800	$ 455,775	$ 305,928	$ 191,550	$ 119,000	$2,024,000	
Price to public	$ 38.000	$ 37.000	$ 12.900	$ 25.750	$ 48.560	$ 25.540	$ 29.750	$ 25.300	
Underwriter's discounts and commission	$ 1.330	$ 1.295	$ 0.452	$ 1.094	$ -	$ 0.894	$ 1.040	$ 0.759	
Gross Proceeds	$ 36.670	$ 35.705	$ 12.448	$ 24.656	$ 48.560	$ 24.646	$ 28.710	$ 24.541	
Estimated company issuance expenses	$ 0.032	N/A	$ 0.013	$ 0.018	$ 0.079	N/A	$ 0.069	$ 0.013	
Net proceeds to company per share	$ 36.670	$ 35.705	$ 12.448	$ 24.656	$ 48.560	$ 24.646	$ 28.710	$ 24.541	
Underwriter's discount as a percent of offering pric	3.5%	3.5%	3.5%	4.2%	0.0%	3.5%	3.5%	3.0%	3.2%
Issuance expense as a percent of offering pric	0.1%	N/A	0.1%	0.1%	0.2%	N/A	0.2%	0.0%	0.2%
Total Issuance and selling expense as as a percent of offering pric	3.6%	3.5%	3.6%	4.3%	0.2%	3.5%	3.7%	3.0%	3.3%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2008-2012
and the Twelve Months Ended December 2013

Years	Aa Rated	A Rated	Baa Rated	Average
2008	6.18%	6.53%	7.24%	6.65%
2009	5.75%	6.04%	7.06%	6.28%
2010	5.24%	5.46%	5.96%	5.55%
2011	4.78%	5.04%	5.57%	5.13%
2012	3.83%	4.13%	4.86%	4.27%
Five-Year Average	5.16%	5.44%	6.14%	5.58%
Months				
Jan-13	3.90%	4.15%	4.66%	4.24%
Feb-13	3.95%	4.18%	4.74%	4.29%
Mar-13	3.95%	4.20%	4.72%	4.29%
Apr-13	3.74%	4.00%	4.49%	4.08%
May-13	3.91%	4.17%	4.65%	4.24%
Jun-13	4.27%	4.53%	5.08%	4.63%
Jul-13	4.44%	4.68%	5.21%	4.78%
Aug-13	4.53%	4.73%	5.28%	4.85%
Sep-13	4.58%	4.80%	5.31%	4.90%
Oct-13	4.48%	4.70%	5.17%	4.78%
Nov-13	4.56%	4.77%	5.24%	4.86%
Dec-13	4.59%	4.81%	5.25%	4.89%
Twelve-Month Average	4.24%	4.48%	4.98%	4.57%
Six-Month Average	4.53%	4.75%	5.24%	4.84%
Three-Month Average	4.54%	4.76%	5.22%	4.84%

Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 30-Year Treasuries

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%	6.07%	6.53%	6.04%	5.46%	5.04%	4.13%	4.48%
Spread vs. 30-year	0.94%	1.01%	1.04%	0.99%	1.46%	1.75%	2.30%	2.27%					1.16%	1.23%	2.25%	1.96%	1.21%	1.13%	1.21%	1.03%

A rated Public Utility Bonds over 30-Year Treasuries

	A-rated	30-Year Treasuries			A-rated	30-Year Treasuries			A-rated	30-Year Treasuries	
Year	Public Utility	Yield	Spread	Year	Public Utility	Yield	Spread	Year	Public Utility	Yield	Spread
Dec-98	6.91%	5.06%	1.85%								
Jan-99	6.97%	5.16%	1.81%	Jan-04	6.15%			Jan-09	6.39%	3.13%	3.26%
Feb-99	7.09%	5.37%	1.72%	Feb-04	6.15%			Feb-09	6.30%	3.59%	2.71%
Mar-99	7.26%	5.58%	1.68%	Mar-04	5.97%			Mar-09	6.42%	3.64%	2.78%
Apr-99	7.22%	5.55%	1.67%	Apr-04	6.35%			Apr-09	6.48%	3.76%	2.72%
May-99	7.47%	5.81%	1.66%	May-04	6.62%			May-09	6.49%	4.23%	2.26%
Jun-99	7.74%	6.04%	1.70%	Jun-04	6.46%			Jun-09	6.20%	4.52%	1.68%
Jul-99	7.71%	5.98%	1.73%	Jul-04	6.27%			Jul-09	5.97%	4.41%	1.56%
Aug-99	7.91%	6.07%	1.84%	Aug-04	6.14%			Aug-09	5.71%	4.37%	1.34%
Sep-99	7.93%	6.07%	1.86%	Sep-04	5.98%			Sep-09	5.53%	4.19%	1.34%
Oct-99	8.06%	6.26%	1.80%	Oct-04	5.94%			Oct-09	5.55%	4.19%	1.36%
Nov-99	7.94%	6.15%	1.79%	Nov-04	5.97%			Nov-09	5.64%	4.31%	1.33%
Dec-99	8.14%	6.35%	1.79%	Dec-04	5.92%			Dec-09	5.79%	4.49%	1.30%
Jan-00	8.35%	6.63%	1.72%	Jan-05	5.78%			Jan-10	5.77%	4.60%	1.17%
Feb-00	8.25%	6.23%	2.02%	Feb-05	5.61%			Feb-10	5.87%	4.62%	1.25%
Mar-00	8.28%	6.05%	2.23%	Mar-05	5.83%			Mar-10	5.84%	4.64%	1.20%
Apr-00	8.29%	5.85%	2.44%	Apr-05	5.64%			Apr-10	5.81%	4.69%	1.12%
May-00	8.70%	6.15%	2.55%	May-05	5.53%			May-10	5.50%	4.29%	1.21%
Jun-00	8.36%	5.93%	2.43%	Jun-05	5.40%			Jun-10	5.46%	4.13%	1.33%
Jul-00	8.25%	5.85%	2.40%	Jul-05	5.51%			Jul-10	5.26%	3.99%	1.27%
Aug-00	8.13%	5.72%	2.41%	Aug-05	5.50%			Aug-10	5.01%	3.80%	1.21%
Sep-00	8.23%	5.83%	2.40%	Sep-05	5.52%			Sep-10	5.01%	3.77%	1.24%
Oct-00	8.14%	5.80%	2.34%	Oct-05	5.79%			Oct-10	5.10%	3.87%	1.23%
Nov-00	8.11%	5.78%	2.33%	Nov-05	5.88%			Nov-10	5.37%	4.19%	1.18%
Dec-00	7.84%	5.49%	2.35%	Dec-05	5.80%			Dec-10	5.56%	4.42%	1.14%
Jan-01	7.80%	5.54%	2.26%	Jan-06	5.75%			Jan-11	5.57%	4.52%	1.05%
Feb-01	7.74%	5.45%	2.29%	Feb-06	5.82%	4.54%	1.28%	Feb-11	5.68%	4.65%	1.03%
Mar-01	7.68%	5.34%	2.34%	Mar-06	5.98%	4.73%	1.25%	Mar-11	5.56%	4.51%	1.05%
Apr-01	7.94%	5.65%	2.29%	Apr-06	6.29%	5.06%	1.23%	Apr-11	5.55%	4.50%	1.05%
May-01	7.99%	5.78%	2.21%	May-06	6.42%	5.20%	1.22%	May-11	5.32%	4.29%	1.03%
Jun-01	7.85%	5.67%	2.18%	Jun-06	6.40%	5.15%	1.25%	Jun-11	5.26%	4.23%	1.03%
Jul-01	7.78%	5.61%	2.17%	Jul-06	6.37%	5.13%	1.24%	Jul-11	5.27%	4.27%	1.00%
Aug-01	7.59%	5.48%	2.11%	Aug-06	6.20%	5.00%	1.20%	Aug-11	4.69%	3.65%	1.04%
Sep-01	7.75%	5.48%	2.27%	Sep-06	6.00%	4.85%	1.15%	Sep-11	4.48%	3.18%	1.30%
Oct-01	7.63%	5.32%	2.31%	Oct-06	5.98%	4.85%	1.13%	Oct-11	4.52%	3.13%	1.39%
Nov-01	7.57%	5.12%	2.45%	Nov-06	5.80%	4.69%	1.11%	Nov-11	4.25%	3.02%	1.23%
Dec-01	7.83%	5.48%	2.35%	Dec-06	5.81%	4.68%	1.13%	Dec-11	4.33%	2.98%	1.35%
Jan-02	7.66%	5.45%	2.21%	Jan-07	5.96%	4.85%	1.11%	Jan-12	4.34%	3.03%	1.31%
Feb-02	7.54%	5.40%	2.14%	Feb-07	5.90%	4.82%	1.08%	Feb-12	4.36%	3.11%	1.25%
Mar-02	7.76%			Mar-07	5.85%	4.72%	1.13%	Mar-12	4.48%	3.28%	1.20%
Apr-02	7.57%			Apr-07	5.97%	4.87%	1.10%	Apr-12	4.40%	3.18%	1.22%
May-02	7.52%			May-07	5.99%	4.90%	1.09%	May-12	4.20%	2.93%	1.27%
Jun-02	7.42%			Jun-07	6.30%	5.20%	1.10%	Jun-12	4.08%	2.70%	1.38%
Jul-02	7.31%			Jul-07	6.25%	5.11%	1.14%	Jul-12	3.93%	2.59%	1.34%
Aug-02	7.17%			Aug-07	6.24%	4.93%	1.31%	Aug-12	4.00%	2.77%	1.23%
Sep-02	7.08%			Sep-07	6.18%	4.79%	1.39%	Sep-12	4.02%	2.88%	1.14%
Oct-02	7.23%			Oct-07	6.11%	4.77%	1.34%	Oct-12	3.91%	2.90%	1.01%
Nov-02	7.14%			Nov-07	5.97%	4.52%	1.45%	Nov-12	3.84%	2.80%	1.04%
Dec-02	7.07%			Dec-07	6.16%	4.53%	1.63%	Dec-12	4.00%	2.88%	1.12%
Jan-03	7.07%			Jan-08	6.02%	4.33%	1.69%	Jan-13	4.15%	3.08%	1.07%
Feb-03	6.93%			Feb-08	6.21%	4.52%	1.69%	Feb-13	4.18%	3.17%	1.01%
Mar-03	6.79%			Mar-08	6.21%	4.39%	1.82%	Mar-13	4.20%	3.16%	1.04%
Apr-03	6.64%			Apr-08	6.29%	4.44%	1.85%	Apr-13	4.00%	2.93%	1.07%
May-03	6.36%			May-08	6.28%	4.60%	1.68%	May-13	4.17%	3.11%	1.06%
Jun-03	6.21%			Jun-08	6.38%	4.69%	1.69%	Jun-13	4.53%	3.40%	1.13%
Jul-03	6.57%			Jul-08	6.40%	4.57%	1.83%	Jul-13	4.68%	3.61%	1.07%
Aug-03	6.78%			Aug-08	6.37%	4.50%	1.87%	Aug-13	4.73%	3.76%	0.97%
Sep-03	6.56%			Sep-08	6.49%	4.27%	2.22%	Sep-13	4.80%	3.79%	1.01%
Oct-03	6.43%			Oct-08	7.56%	4.17%	3.39%	Oct-13	4.70%	3.68%	1.02%
Nov-03	6.37%			Nov-08	7.60%	4.00%	3.60%	Nov-13	4.77%	3.80%	0.97%
Dec-03	6.27%			Dec-08	6.52%	2.87%	3.65%	Dec-13	4.81%	3.89%	0.92%
								Average:			
								12-months			1.03%
								6-months			0.99%
								3-months			0.97%

Common Equity Risk Premiums
Years 1926-2013

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.17%	4.57%	7.60%	3.01%
Average Across All Interest Rates	12.05%	6.26%	5.79%	5.15%
High Interest Rates	11.93%	7.95%	3.98%	7.28%

Source of Information: Stocks, Bonds, Bills, and Inflation (SBBI) 2014 Classic Yearbook

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
2012	16.00%	10.68%	2.41%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
1943	25.90%	2.83%	2.48%
2011	2.11%	17.95%	2.48%
1938	31.12%	6.13%	2.52%
1936	33.92%	6.74%	2.55%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.16%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.67%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.18%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2008-2012
and the Twelve Months Ended December 2013

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2008	1.82%	2.00%	2.24%	2.80%	3.17%	3.67%	4.36%	4.28%
2009	0.47%	0.96%	1.43%	2.19%	2.81%	3.26%	4.11%	4.08%
2010	0.32%	0.70%	1.11%	1.93%	2.62%	3.21%	4.03%	4.25%
2011	0.18%	0.45%	0.75%	1.52%	2.16%	2.79%	3.62%	3.91%
2012	0.18%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
Five-Year Average	0.59%	0.88%	1.18%	1.84%	2.40%	2.95%	3.73%	3.89%
Months								
Jan-13	0.15%	0.27%	0.39%	0.81%	1.30%	1.91%	2.68%	3.08%
Feb-13	0.16%	0.27%	0.40%	0.85%	1.35%	1.98%	2.78%	3.17%
Mar-13	0.15%	0.26%	0.39%	0.82%	1.32%	1.96%	2.78%	3.16%
Apr-13	0.12%	0.23%	0.34%	0.71%	1.15%	1.76%	2.55%	2.93%
May-13	0.12%	0.25%	0.40%	0.84%	1.31%	1.93%	2.73%	3.11%
Jun-13	0.14%	0.33%	0.58%	1.20%	1.71%	2.30%	3.07%	3.40%
Jul-13	0.12%	0.34%	0.64%	1.40%	1.99%	2.58%	3.31%	3.61%
Aug-13	0.13%	0.36%	0.70%	1.52%	2.15%	2.74%	3.49%	3.76%
Sep-13	0.12%	0.40%	0.78%	1.60%	2.22%	2.81%	3.53%	3.79%
Oct-13	0.12%	0.34%	0.63%	1.37%	1.99%	2.62%	3.38%	3.68%
Nov-13	0.12%	0.30%	0.58%	1.37%	2.07%	2.72%	3.50%	3.80%
Dec-13	0.13%	0.34%	0.69%	1.58%	2.29%	2.90%	3.63%	3.89%
Twelve-Month Average	0.13%	0.31%	0.54%	1.17%	1.74%	2.35%	3.12%	3.45%
Six-Month Average	0.12%	0.35%	0.67%	1.47%	2.12%	2.73%	3.47%	3.76%
Three-Month Average	0.12%	0.33%	0.63%	1.44%	2.12%	2.75%	3.50%	3.79%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated January 1, 2014

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2014	First	0.2%	0.4%	1.6%	2.9%	3.9%	4.7%	5.5%
2014	Second	0.2%	0.5%	1.7%	3.0%	4.0%	4.8%	5.6%
2014	Third	0.3%	0.6%	1.8%	3.1%	4.1%	4.9%	5.7%
2014	Fourth	0.3%	0.8%	2.0%	3.3%	4.2%	5.0%	5.8%
2015	First	0.5%	0.9%	2.1%	3.3%	4.3%	5.1%	5.9%
2015	Second	0.6%	1.1%	2.3%	3.4%	4.4%	5.2%	6.0%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
January 3, 2014	1.9%	+	6.78%	=	8.68%

DCF Result for the S&P 500 Composite

D/P	(1+.5g)	+	g	=	k
1.93%	(1.0484)	+	9.67%	=	11.69%
where:	Price (P)	at	31-Dec-13	=	1848.36
	Dividend (D)	for	3rd Qtr. '13	=	8.91
	Dividend (D)		annualized	=	35.64
	Growth (g)	by	First Call	=	9.67%

Summary

Value Line			8.68%
S&P 500			11.69%
Average			10.19%
Risk-free Rate of Return (Rf)			4.50%
Forecast Market Premium			5.69%
Historical Market Premium	(Rm)	(Rf)	
1926-2013 Arith. mean	12.11%	4.08%	8.03%
Average - Forecast/Historical			6.86%

This phenomenon can also be viewed graphically, as depicted in the Graph 7-2. The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the line, indicating that these deciles have had returns in excess of that which is appropriate for their systematic risk.

Table 7-6: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ Long-Term Returns in Excess of CAPM

Decile	Beta*	Arithmetic Mean Return (%)	Actual Return in Excess of Riskless Rate** (%)	CAPM Return in Excess of Riskless Rate† (%)	Size Premium (Return in Excess of CAPM) (%)
1-Largest	0.91	11.13	6.03	6.37	-0.33
2	1.03	13.09	8.00	7.20	0.80
3	1.10	13.68	8.59	7.66	0.93
4	1.13	14.12	9.03	7.84	1.19
5	1.16	14.88	9.79	8.07	1.72
6	1.19	15.11	10.02	8.26	1.75
7	1.24	15.48	10.39	8.64	1.75
8	1.30	16.62	11.53	9.05	2.48
9	1.35	17.23	12.14	9.37	2.76
10-Smallest	1.40	20.88	15.79	9.77	6.01
Mid-Cap 3-5	1.12	14.02	8.93	7.79	1.14
Low-Cap 6-8	1.23	15.51	10.41	8.54	1.87
Micro-Cap 9-10	1.36	18.38	13.29	9.45	3.84

Data from 1926–2013.

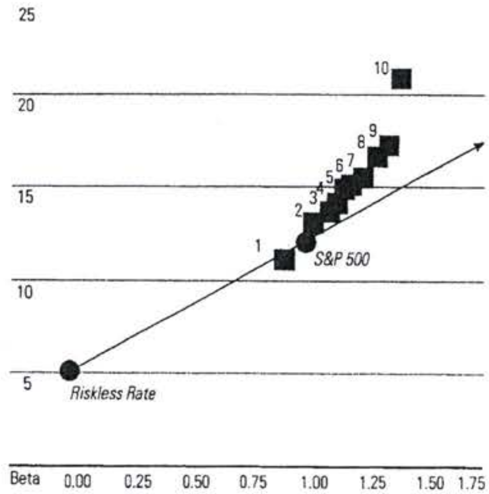
*Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2013.

**Historical riskless rate measured by the 88-year arithmetic mean income return component of 20-year government bonds (5.09 percent).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (12.05 percent) minus the arithmetic mean income return component of 20-year government bonds (5.09 percent) from 1926–2013.

Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2014 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Graph 7-2: Security Market Line Versus Size-Decile Portfolios of the NYSE/AMEX/NASDAQ



Data from 1926–2013.

Serial Correlation in Small Company Stock Returns

In four of the last ten years, large-capitalization stocks (deciles 1–2 NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9–10 NYSE/AMEX/NASDAQ). This has led some to speculate that there is no size premium, but statistical evidence suggests that periods of underperformance should be expected. For instance, since 1926, large-capitalization stocks have outperformed small-capitalization stocks nearly 50 percent of the time.

It should be noted, however, that large-capitalization stocks' average historical outperformance has been less than the average historical outperformance of small-capitalization stocks.

History tells us that small companies are riskier than large companies. Table 7-1 [see page 100] shows the standard deviation (a measure of risk) for each decile of the NYSE/AMEX/NASDAQ. As one moves from larger to smaller deciles, the standard deviation of return grows. Investors are compensated for taking on this additional risk by the higher returns provided by small companies. It is important to note, however, that the risk/return profile is over the long term. If small companies did not provide higher long-term returns, investors would be more inclined to invest in the less risky stocks of large companies.

Comparable Earnings Approach
Price Stability of 90 to 100; Betas of .55 to .95; and Technical Rank of 2, 3 & 4
Timeliness of 2, 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B++ & A;
Using Non-Utility Companies with

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Alleghany Corp.	INSPRPTY	3	2	A	90	0.75	3
AmerisourceBergen	MEDICNON	3	1	A	95	0.70	3
AptarGroup	PACKAGE	3	2	B++	95	0.90	3
Ball Corp.	PACKAGE	4	2	B++	95	0.85	3
Beam Inc.	BEVERAGE	4	3	B++	100	0.90	3
Bemis Co.	PACKAGE	4	2	A	90	0.90	3
Berkley (W.R.)	INSPRPTY	3	2	B++	95	0.65	3
Bio-Rad Labs. 'A'	MEDICNON	4	2	B++	90	0.85	3
Brown & Brown	FINSERV	3	1	A	95	0.75	3
Campbell Soup	FOODPROC	4	2	B++	100	0.60	3
Cincinnati Financial	INSPRPTY	3	2	B++	95	0.85	4
Clorox Co.	HOUSEPRD	4	2	B++	100	0.60	3
Commerce Bancshs.	BANKMID	3	1	A	90	0.85	3
ConAgra Foods	FOODPROC	4	1	A	100	0.65	3
Cullen/Frost Bankers	BANK	4	1	A	95	0.80	2
DaVita HealthCare	MEDSERV	2	2	B++	90	0.70	2
Dentsply Int'l	MEDICINV	3	2	B++	90	0.95	3
Dollar General	RETAIL	2	2	B++	90	0.60	3
Ecolab Inc.	CHEMSPEC	3	1	A	100	0.70	3
Equifax Inc.	INFOSER	3	2	A	90	0.90	3
Fidelity National	FINSERV	3	2	A	90	0.80	3
Fiserv Inc.	ITSERV	3	2	B++	95	0.90	3
Forest Labs.	DRUG	3	3	A	90	0.80	2
Gallagher (Arthur J.)	FINSERV	3	1	A	90	0.75	3
Hanover Insurance	INSPRPTY	3	2	B++	95	0.75	4
Henry (Jack) & Assoc.	ITSERV	3	2	B++	95	0.85	2
Hershey Co.	FOODPROC	4	2	B++	100	0.60	3
Hormel Foods	FOODPROC	3	1	A	100	0.65	4
Int'l Flavors & Frag.	CHEMSPEC	3	1	A	95	0.85	3
Kellogg	FOODPROC	2	1	A	100	0.60	3
Kroger Co.	GROCERY	2	2	B++	95	0.65	4
L-3 Communic.	DEFENSE	2	2	B++	90	0.90	3
Laboratory Corp.	MEDSERV	3	1	A	100	0.70	2
Lorillard Inc.	TOBACCO	3	2	A	90	0.60	3
Mercury General	INSPRPTY	3	2	B++	90	0.75	3
Molson Coors Brewing	BEVERAGE	3	2	B++	90	0.75	3
Motorola Solutions	TELEQUIP	3	1	A	100	0.80	2
NeuStar Inc.	TELEQUIP	3	3	B++	90	0.85	2
Owens & Minor	MEDICNON	3	2	A	90	0.75	3
Paychex Inc.	ITSERV	3	1	A	95	0.85	3
Philip Morris Int'l	TOBACCO	3	2	B++	95	0.75	3
Praxair Inc.	CHEMSPEC	2	2	A	90	0.95	2
RLI Corp.	INSPRPTY	3	2	B++	95	0.75	4
Rollins Inc.	INDUSRV	3	2	A	90	0.85	3
Ross Stores	RETAILSL	3	2	A	90	0.75	3
Stericycle Inc.	ENVIRONM	3	2	B++	95	0.65	3
Synopsys Inc.	SOFTWARE	3	1	A	95	0.80	3
Teleflex Inc.	MEDICINV	4	2	A	90	0.75	3
Tim Hortons	RESTRNT	3	2	A	95	0.85	3
Total System Svcs.	FINSERV	3	2	B++	95	0.80	3
United Parcel Serv.	AIRTRANS	3	1	A	95	0.90	3
Waste Management	ENVIRONM	3	2	A	95	0.80	3
Weis Markets	GROCERY	4	1	A	95	0.65	3
West Pharmac. Svcs.	MEDICNON	4	2	B++	90	0.80	3
Average		3	2	A	94	0.77	3
Electric Group	Average	3	2	B++	98	0.73	3

Source of Information: Value Line Investment Survey for Windows, December 2013

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2008-2012 and
Projected 3-5 Year Returns

Company	2008	2009	2010	2011	2012	Average	Projected 2016-18
Alleghany Corp.	4.4%	4.4%	4.6%	4.9%	2.6%	4.2%	7.0%
AmerisourceBergen	17.3%	18.8%	21.6%	24.6%	28.8%	22.2%	32.0%
AptarGroup	13.6%	9.9%	13.6%	14.2%	11.8%	12.6%	13.0%
Ball Corp.	32.3%	24.3%	35.8%	36.6%	36.5%	33.1%	27.0%
Beam Inc.	12.4%	7.2%	7.6%	3.2%	8.6%	7.8%	9.5%
Bemis Co.	12.3%	8.2%	10.5%	11.6%	10.6%	10.6%	15.0%
Berkley (W.R.)	16.5%	10.2%	11.4%	7.7%	8.8%	10.9%	11.0%
Bio-Rad Labs. 'A'	11.2%	11.5%	10.8%	10.2%	8.1%	10.4%	11.0%
Brown & Brown	13.4%	11.2%	10.7%	10.0%	10.2%	11.1%	12.5%
Campbell Soup	60.5%	105.9%	91.1%	77.8%	87.2%	84.5%	52.5%
Cincinnati Financial	8.2%	4.5%	5.4%	2.4%	7.7%	5.6%	9.0%
Clorox Co.	-	-	NMF	NMF	NMF	-	NMF
Commerce Bancshs.	12.0%	9.0%	11.0%	11.8%	12.4%	11.2%	11.0%
ConAgra Foods	9.7%	14.7%	15.8%	16.2%	17.3%	14.7%	18.5%
Cullen/Frost Bankers	11.8%	9.5%	10.1%	9.5%	9.8%	10.1%	9.5%
DaVita HealthCare	19.2%	19.8%	22.8%	22.5%	16.3%	20.1%	20.0%
Dentsply Int'l	18.0%	15.1%	15.1%	15.7%	14.5%	15.7%	12.5%
Dollar General	3.8%	10.0%	15.5%	16.4%	19.1%	13.0%	18.0%
Ecolab Inc.	29.5%	23.9%	24.9%	10.5%	14.7%	20.7%	15.0%
Equifax Inc.	24.6%	18.4%	17.5%	18.1%	18.6%	19.4%	17.0%
Fidelity National	3.3%	1.2%	7.0%	7.6%	8.0%	5.4%	9.5%
Fiserv Inc.	20.3%	18.2%	19.0%	20.3%	20.7%	19.7%	18.0%
Forest Labs.	25.6%	21.8%	23.3%	18.0%	0.7%	17.9%	7.5%
Gallagher (Arthur J.)	15.1%	14.9%	14.8%	11.9%	11.8%	13.7%	13.5%
Hanover Insurance	9.7%	8.0%	6.2%	1.3%	1.8%	5.4%	9.5%
Henry (Jack) & Assoc.	17.5%	16.5%	15.7%	15.6%	15.8%	16.2%	15.5%
Hershey Co.	135.3%	69.3%	65.1%	76.4%	71.4%	83.5%	46.0%
Hormel Foods	14.2%	16.1%	17.0%	17.8%	17.7%	16.6%	16.5%
Int'l Flavors & Frag.	38.6%	27.9%	26.4%	24.1%	26.1%	28.6%	20.5%
Kellogg	79.3%	53.3%	57.8%	69.9%	53.6%	62.8%	30.5%
Kroger Co.	24.1%	23.2%	21.1%	30.0%	33.8%	26.4%	22.5%
L-3 Communic.	14.7%	13.2%	14.0%	14.4%	14.8%	14.2%	12.0%
Laboratory Corp.	30.4%	25.3%	23.7%	25.8%	24.4%	25.9%	15.5%
Lorillard Inc.	NMF	NMF	-	NMF	NMF	-	NMF
Mercury General	7.7%	10.0%	6.4%	8.2%	6.3%	7.7%	10.0%
Molson Coors Brewing	8.6%	10.0%	8.6%	8.8%	5.5%	8.3%	8.5%
Motorola Solutions	-	-	11.1%	17.0%	29.2%	19.1%	52.0%
NeuStar Inc.	20.2%	20.1%	17.8%	24.6%	24.1%	21.4%	22.5%
Owens & Minor	14.7%	14.3%	14.4%	13.4%	11.3%	13.6%	15.0%
Paychex Inc.	48.1%	39.8%	34.0%	34.4%	34.2%	38.1%	37.0%
Philip Morris Int'l	91.9%	111.0%	207.0%	NMF	NMF	136.6%	NMF
Praxair Inc.	33.3%	23.6%	20.6%	30.5%	27.9%	27.2%	24.0%
RLI Corp.	15.3%	12.2%	13.9%	14.7%	10.9%	13.4%	8.5%
Rollins Inc.	30.2%	30.2%	30.2%	31.1%	31.4%	30.6%	26.0%
Ross Stores	30.7%	38.3%	41.6%	44.0%	44.5%	39.8%	29.0%
Stericycle Inc.	22.8%	21.1%	20.4%	20.2%	18.7%	20.6%	14.5%
Synopsys Inc.	13.1%	10.8%	9.1%	10.2%	9.8%	10.6%	9.5%
Teleflex Inc.	12.9%	8.6%	8.9%	6.1%	7.4%	8.8%	11.5%
Tim Hortons	26.2%	25.5%	24.7%	33.2%	33.9%	28.7%	35.0%
Total System Svcs.	25.6%	18.7%	15.9%	16.9%	17.1%	18.8%	13.0%
United Parcel Serv.	52.8%	30.4%	44.7%	59.6%	NMF	46.9%	45.0%
Waste Management	18.4%	15.7%	16.2%	16.6%	15.2%	16.4%	19.0%
Weis Markets	7.1%	9.1%	9.4%	10.1%	10.4%	9.2%	9.0%
West Pharmac. Svcs.	16.8%	12.5%	11.6%	12.5%	13.3%	13.3%	14.5%
Average						23.1%	18.9%
Median						16.3%	15.0%
Average (excluding values <8% and >20%)						13.3%	13.3%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.