Table of Contents
Commission Conference Agenda
June 9, 2016

Item 1

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Telecommunications (D. Flores, S. Deas)
Office of the General Counsel (K. Young, S. Hopkins)

RE: Application for Certificate of Authority to Provide Telecommunications Service

AGENDA: 6/9/2016 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

Please place the following Application for Certificate of Authority to Provide Telecommunications Service on the consent agenda for approval.

DOCKET NO.	COMPANY NAME	CERT. NO.
160052-TX	Airbus DS Communications, Inc.	8887
160063-TX	SBA DAS & Small Cells, LLC	8890
160064-TX	INDIGITAL, LLC d/b/a INdigital	8889

The Commission is vested with jurisdiction in this matter pursuant to Section 364.335, Florida Statutes. Pursuant to Section 364.336, Florida Statutes, certificate holders must pay a minimum annual Regulatory Assessment Fee if the certificate is active during any portion of the calendar year. A Regulatory Assessment Fee Return Notice will be mailed each December to the entity listed above for payment by January 30.

Item 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Slemkewicz, Fletcher, Mouring)
Division of Economics (Wu)
Division of Engineering (Wooten)
Office of the General Counsel (Brownless)

RE: Docket No. 160039-EI – Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On February 24, 2016, Gulf Power Company (Gulf) filed a petition seeking approval to create a regulatory asset and defer recovery of the amounts related to the retirement of Plant Smith Units 1 and 2 (Units). The recovery of the regulatory asset would be deferred to a future proceeding with an effective date after the expiration date of the Stipulation approved in Order No. PSC-13-0670-S-EI,[1] which is the last billing cycle in June 2017. The decision to retire the Units was made after Gulf finalized its Mercury and Air Toxics Standards (MATS) rule compliance strategy for each of its coal-fired units. At December 31, 2015, the Net Book Value of the Units

[1]Order No. PSC-13-0670-S-EI, issued December 19, 2013, in Docket No. 130140-EI, *In re: Petition for rate increase by Gulf Power Company.*

was approximately $61.9 million and the estimated remaining inventory balance was $2.9 million. The Office of Public Counsel is listed as an interested person in this docket.

This recommendation addresses the creation of the regulatory asset and the deferral of its recovery to a future proceeding. The Commission has jurisdiction over this matter pursuant to Sections 366.04 and 366.06, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the Commission approve Gulf's request to create a regulatory asset related to the retirement of Plant Smith Units 1 and 2 and defer the recovery of the regulatory asset to a future proceeding?

Recommendation: Yes. The Commission should approve Gulf's request to create a regulatory asset related to the retirement of Plant Smith Units 1 and 2 and defer the recovery of the regulatory asset to a future proceeding. Further, the Commission should find that the approval to record the regulatory asset for accounting purposes does not limit the Commission's ability to review the amounts for reasonableness in future proceedings in which the regulatory asset is included. (Slemkewicz, Wooten, Wu)

Staff Analysis: On February 24, 2016, Gulf filed a petition seeking approval to create a regulatory asset and defer recovery of the amounts related to the retirement of Plant Smith Units 1 and 2 (Units). Gulf's decision to retire the units was based on its MATS rule compliance strategy for its coal-fired generating units. Unit 1 began service in 1965 and was previously scheduled to be retired in 2030. Unit 2 began service in 1967 and was previously scheduled to be retired in 2032. Based on the MATS evaluation, the Units were retired on March 31, 2016. At December 31, 2015, the Net Book Value of the Units was $61,880,482 and the estimated remaining inventory balance was $2,852,159.

In its petition, Gulf asserts that its best option for compliance with MATS is the retirement of Plant Smith Units 1 and 2. Staff requested the MATS compliance alternatives that Gulf explored in an effort to determine the accuracy of this determination. In response to this request, Gulf submitted the Plant Smith Asset Evaluation, dated December 11, 2014.[2] After a review of the provided analysis, staff is satisfied that the early retirement of Plant Smith Units 1 and 2 is the most cost-effective alternative.

Because the Units are being retired early, certain entries must be made to Gulf's books and records. Rule 25-6.0436(6), Florida Administrative Code (F.A.C.), requires a utility to compile an annual depreciation status report showing changes to categories of depreciation that will require a revision. In addition, Rule 25-6.0436(7)(a), F.A.C., provides that:

> Prior to the date of retirement of major installations, the Commission shall approve capital recovery schedules to correct associated calculated deficiencies where a utility demonstrates that (1) replacement of an installation or group of installations is prudent and (2) the associated investment will not be recovered by the time of retirement through the normal depreciation process.

Gulf's current depreciation rates are based on retirement dates of 2030 and 2032 for the Units. Therefore, the investment in the Units will not be recovered through the normal depreciation process due to the early retirement of the Units.

[2]Confidential Document No. 02442-16, filed April 25, 2016, in response to Staff's Second Data Request Item No. 1, in Docket No. 160039-EI, *In re: Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company*.

As a result of the Stipulation,[3] Gulf's depreciation and amortization accrual rates in effect as of the effective date of the Stipulation remain in effect. Also, Gulf is not required to file any depreciation or dismantlement studies during the term of the Stipulation that ends with the last billing cycle of June, 2017. However, Gulf is required to file depreciation and dismantlement studies by either December 31, 2018, or a period defined as not more than 1 year nor less than 60 days before the filing of its next general rate proceeding, whichever is sooner.

Based on a review of Gulf's filing and its responses to Staff's First Data Request,[4] it is staff's opinion that the Units' Net Book Value of $61,880,482 and the estimated remaining inventory balance of $2,852,159 represent the appropriate amounts of the proposed regulatory asset as of December 31, 2015. The actual amounts to be recorded as a regulatory asset will be slightly less due to the additional accumulated depreciation incurred between January 1, 2016, and March 31, 2016.

The early retirement of the Units will require that future revisions be made to the depreciation rates, amortization, and capital recovery schedules. As previously stated, Gulf is generally not required to file any depreciation or dismantlement studies before December 31, 2018. The concept of deferral accounting allows companies to defer costs and seek recovery through rates at a later time. The alternative would be for a company to seek a rate case each time it experiences an exogenous event. In staff's opinion, it is appropriate to create a regulatory asset for the amounts associated with the early retirement of the Units and defer recovery until the amounts can be included in the next depreciation or dismantlement studies. Further, the Commission should find that the approval to record the regulatory asset for accounting purposes does not limit the Commission's ability to review the amounts for reasonableness in future proceedings in which the regulatory asset is included.

[3]Document No. 07112-13, filed November 22, 2013, in Docket No. 130140-EI, *In re: Petition for rate increase by Gulf Power Company* (pp. 12-13).
[4]Document No. 01656-16, filed March 30, 2016, in Docket No. 160039-EI, *In re: Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company*.

Issue 2: Should this docket be closed?

Recommendation: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, this docket should be closed upon the issuance of a consummating order. (Brownless)

Staff Analysis: At the conclusion of the protest period, if no protest is filed this docket should be closed upon the issuance of a consummating order.

Item 3

FILED MAY 26, 2016
DOCUMENT NO. 03216-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Barrett, Lester) PL MCB MC ALM
Office of the General Counsel (Brownless)

RE: Docket No. 160096-EI – Joint petition for approval of modifications to risk management plans by Duke Energy Florida, Florida Power & Light Company, Gulf Power Company and Tampa Electric Company.

AGENDA: 06/09/16 – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On April 22, 2016, Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL), Tampa Electric Company (TECO), and Gulf Power Company (Gulf) (Petitioners or IOUs) filed a joint petition seeking approval of modifications to their respective Risk Management Plans (Joint Petition). FPL, TECO, and Gulf are seeking approval of modifications to their respective 2016 Risk Management Plans, noting that the 2016 plans were approved in Order No. PSC-15-0586-FOF-EI (2015 Fuel Order).[1] DEF does not join in seeking to modify its 2016 Risk Management Plan, because DEF believes its current Risk Management Plan affords it the ability to meet the goals proposed by the other petitioners. The Petitioners propose modifications to the 2017 Risk Management Plans, which will be considered for approval in November's annual hearing in the Fuel Cost Recovery Clause docket (Docket No. 160001-EI).

[1] Order No. PSC-15-0586-FOF-EI, issued December 23, 2015, in Docket No: 150001-EI, *In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.*

The Petitioners state that in the 2015 Fuel Order (at page 9), the Commission directed the Petitioners to explore possible changes to the current hedging protocol in order to minimize potential losses to customers in periods of falling natural gas prices.

On January 25, 2016, an informal meeting between Commission staff and interested persons was held to discuss options and procedures for possible changes to the hedging process to minimize potential losses to customers. Representatives from DEF, FPL, TECO, and Gulf participated in the meeting, although no specific actions were developed.

The Petitioners contend this joint proposal achieves the objective expressed in the 2015 Fuel Order to bring forward possible changes to the current hedging protocol in order to minimize potential losses to customers. The Petitioners have identified company-specific commitments and each proposes to:

- Reduce their respective annual maximum percentage of fuel purchases targeted for hedges; and

- Reduce the period of time over which hedges may be placed pursuant to each respective Risk Management Plan.

On April 26, 2016, the Office of Public Counsel (OPC) filed its Notice of Intervention. By Order No. PSC-16-0174-PCO-EI, issued April 29, 2016, the Commission acknowledged OPC's intervention.

On May 10, 2016, DEF, FPL, TECO, and Gulf filed responses to staff's first data request.

The Petitioners propose that the Commission consider this Petition on a proposed agency action (PAA) track and approve the IOUs' modified 2016 Risk Management Plans,[2] to be effective within 15 days following the Commission vote and remain in effect during the pendency of any protest of the PAA Order.

The Commission has jurisdiction to consider this matter pursuant to Section 366.06, Florida Statutes (F.S.).

[2]With the exception of DEF, as described in the Analysis to follow.

Issue 1: Should the Commission approve the Joint Petition to modify the IOUs' Risk Management Plans?

Recommendation: Yes, the Commission should approve the Joint Petition to modify the IOUs' Risk Management Plans. (Barrett, Lester)

Staff Analysis: Risk Management Plans, in general, set forth the strategy and parameters each company will adhere to in their company-specific hedging programs for fuel procurement in the forward year and beyond.[3] These annual plans are reviewed as part of the fuel procurement process in the annual Fuel Cost Recovery Clause (Fuel Clause) hearing. As noted in the 2015 Fuel Order, hedging allows utilities to manage the risk of volatile swings in the price of fuel, specifically natural gas.

Background on Fuel Hedging and Risk Management Plans

Prior to 2001, IOUs carried out a small number of financial hedging transactions. In response to significant fluctuations in the price of natural gas and fuel oil during 2000 and 2001, the Commission raised issues regarding the utilities' management of fuel price risk as part of the 2001 Fuel Clause proceeding. The specific issues raised involved the reasonableness of hedging as a tool to manage fuel price risk and the appropriate regulatory treatment of hedging gains and losses. These issues were spun off to Docket No. 011605-EI for further investigation.

At the hearing for Docket No. 011605-EI, parties reached a settlement of all issues. By Order No. PSC-02-1484-FOF-EI (Hedging Order),[4] the Commission approved a settlement that provided a framework that incorporated hedging activities into fuel procurement activities. For natural gas, fuel oil, and purchased power, the settlement allowed Florida's generating IOUs to charge prudently incurred hedging gains and losses to the fuel clause. The Hedging Order specified that the Commission would review each IOU's hedging activities as part of the annual fuel proceeding.

The Hedging Order required utilities to file Risk Management Plans as part of their true-up filings. The intent of this requirement was to allow this Commission and parties to the Fuel Clause docket to monitor utility hedging activities. As part of the annual final true-up filings, utilities were required to state the volumes of fuel hedged, the type of hedging instruments, the average length of the term of the hedge positions, and fees associated with hedging transactions.

Although the Hedging Order allowed utilities flexibility in the development of Risk Management Plans, the order also set forth guidelines utilities were to follow. For example, the order required that Risk Management Plans identify the objectives of the hedging programs and the minimum quantities to be hedged. The order also required that plans provide mechanisms and controls for

[3]Risk Management Plans are generally filed annually in the third quarter of each year, and are subject to approval in the fuel clause hearing, usually scheduled for early November. The 2016 Risk Management Plans, which were reviewed in the fuel clause proceeding in 2015, were approved in the 2015 Fuel Order. Even though DEF presents information about its 2017 Risk Management Plan, the 2017 plans have not been filed with the Commission as of the date of this recommendation.

[4]Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures.*

the proper oversight of hedging activities within the utility, as well as include the method for assessing and monitoring fuel price risk.

In tandem with Docket No. 011605-EI, Commission staff conducted a review of the internal controls of the IOUs and published the findings in a report entitled "Internal Controls of Florida's Investor-Owned Utilities for Fuel and Wholesale Energy Transactions." This study examined the practices, procedures, controls, and policies these companies followed when purchasing fossil fuels and wholesale energy. The study period looked at data from 1998 through 2001. The study concluded that Florida's IOUs had engaged in physical hedging in fuel procurement but very limited financial hedging. At the time, the IOUs had not set up the proper controls to engage in extensive financial hedging.

The next time the Commission reviewed the policy on hedging was at the 2007 Fuel Clause hearing. Parties raised questions regarding the period over which the Commission was determining the prudency of costs of hedging activities. The Commission deferred the decision on the prudence of 2007 hedging activity costs to 2008 to allow for sufficient development of data and review of the matter.

Following the 2007 Fuel Clause hearing, two audits of the IOUs' hedging programs were conducted by Commission staff. First, staff conducted a management audit reviewing the IOUs' hedging programs to assess the costs and benefits realized since the entry of the Hedging Order. The IOUs' accounting treatment of 2007 hedging activities was also audited to determine compliance with their risk management plans filed in 2006.

The management audit assessed the current and historical strategies of the fuel procurement hedging programs within each company at that time, evaluated hedging objectives set forth in each company's Risk Management Plan, and quantified the net costs and benefits of each company's hedging program. Specifically, the structure and performance of hedging natural gas and fuel oil through the use of physical purchases and/or financial instruments for the years 2003 through 2007 was examined. Information was collected regarding each company's policies and procedures, organizational charts, Risk Management Plans, and historical hedging transactions. An analysis was conducted of each company's hedging program. In June 2008, a report was issued entitled "Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities."

In its 2008 report, Commission staff found that each company shared a universal goal in securing financial hedges for fuel procurement; that is, to reduce the impacts of price extremes that can occur in the natural gas and fuel markets. In their hedging activities, the companies were not attempting to speculate on price movements in the market. Rather, each was working to stabilize annual fuel costs by initializing and settling financial hedging transactions through authorized financial counterparties. The volumes of natural gas and fuel oil hedged were less than the total volumes expected to be purchased. Overall, staff believed that the use of financial hedges for fuel purchases provided a benefit to utility customers.

On January 31, 2008, in response to the deferral of the determination of prudence related to 2007 hedging costs, FPL filed a petition requesting that the Commission approve FPL's proposed volatility mitigation mechanism (VMM) as an alternative to FPL's hedging program. The VMM proposal involved FPL collecting under recoveries of fuel costs over two years instead of one year, as was, and is, the current practice. On March 11, 2008, a workshop was held to get stakeholder input on this proposal. All parties to the 2002 settlement attended.

By Order No. PSC-08-0316-PAA-EI,[5] the Commission clarified the Hedging Order in several areas. IOUs were required to file a Hedging Information Report by August 15th of each year. This order also specified that the Commission would make a determination of prudence of hedging results for the twelve month period ending July 31 of the current year. Additional workshops were held on June 9, 2008, and June 24, 2008, regarding FPL's VMM petition and guidelines for hedging programs. FPL withdrew its VMM petition on August 5, 2008.

Following the workshops, the Commission established guidelines for Risk Management Plans by Order No. PSC-08-0667-PAA-EI.[6] At that time, the Commission determined that utility hedging programs provide benefits to customers. The guidelines clarified the timing and content of regulatory filings for hedging activities, but allowed the IOUs flexibility in creating and implementing Risk Management Plans.

Each year in the Fuel Clause, staff auditors review utility hedging results for the twelve month period ending July 31 of the current year. In addition, each year the Commission votes on the IOUs' proposed Risk Management Plans for hedging transactions the utility will enter the following year and beyond. As noted earlier, the 2016 Risk Management Plans were approved in the 2015 Fuel Order, which found:

> Each plan provides the appropriate governance for a well-disciplined and prudently managed utility hedging program and is consistent with the Hedging Guidelines. These plans are structured to reduce price volatility risk in a structured manner.[7]

In the hearing for the 2015 Fuel Clause, the Commission evaluated the evidence presented in that record, which in large part consisted of arguments to either completely eliminate hedging or to continue the hedging procedures in place at that time. In the 2015 Fuel Order, the Commission decided to continue hedging with the specific directive to staff to explore possible changes to the current hedging protocol to minimize potential losses to customers. Additionally, the 2015 Fuel Order set forth that any changes to the hedging protocol should be prospective and that the current hedges should be allowed to terminate on their original contract dates.

Petition

As stated in the Joint Petition, DEF, FPL, TECO and Gulf estimate that 66 percent, 71 percent, 50 percent, and 65 percent, respectively, of their forecasted generation in 2016 will be from natural gas. This dependence on natural gas means customers have significant exposure to the uncertainties of natural gas prices. Even though natural gas prices have trended downward in

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[5]Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.*
[6]Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.*
[7]2015 Fuel Order at 9.

recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty. The Petitioners believe the recent downward trend in natural gas market prices cannot continue indefinitely, and factors such as production costs, weather, environmental regulations, and exportation will impact natural gas supply and demand, as well as natural gas price volatility.

The Petitioners recognize that the amount of hedging undertaken by a utility is a matter of business judgment reflecting a necessary balance between the benefits of reduced fuel price volatility on customers' bills through hedging and, the cost of those hedges if prices fall. That balance is reflected in the amount of fuel hedged.[8] Accordingly, and in response to the Commission's directive to explore possible changes to the current hedging protocol, the Petitioners propose a two-step initiative to minimize potential losses to customers in periods of falling fuel prices.

Targets

The Petitioners propose to adjust hedging target ranges. For fuel purchases in 2017 that would be hedged under the Commission-approved 2016 Risk Management Plans, FPL, TECO and Gulf propose to reduce by up to 25 percent the maximum percentage limits planned for procurement with hedging instruments.[9] As noted previously, DEF proposes to implement target reductions beginning with the targets that will be included in its 2017 Risk Management Plan. Acknowledging that a portion of these hedges for 2017 have already been executed, this proposed limitation only applies to the portion that remains unhedged for 2017.

For fuel purchases for 2018 and extending to future periods that would be hedged under the Commission-approved 2016 Risk Management Plans, all four Petitioners propose to reduce by 25 percent the upper limit targets and ranges planned for procurement with hedging instruments.[10] Beginning with the 2017 Risk Management Plan for 2018 procurement and continuing thereafter, each of the IOUs will reduce the annual percentage of its fuel purchases for the ensuing 12-month period that are targeted to be hedged by 25 percent from the target and/or range approved in its 2016 Risk Management Plan. Because the Petitioners have requested confidential classification for the hedging target ranges identified in their 2016 Risk Management Plans, staff cannot disclose the actual ranges in those plans.[11]

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[8]FPL clarified that the reduced hedging targets apply to the total targets and ranges for all hedges, and the reduced hedging targets and ranges have no impact on the gas reserves guidelines approved in Order Nos. PSC-15-0038-FOF-EI and PSC-15-0284-FOF-EI. See: Order No. PSC-15-0038-FOF-EI, issued January 12, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*, and Order No. PSC-15-0284-FOF-EI, issued July 14, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

[9]DEF agrees with and joins FPL, TECO, and Gulf in the proposed plan to reduce the maximum projected fuel purchases for calendar year 2017 that would be hedged during the remainder of 2016. However, DEF believes its 2016 Risk Management Plan affords it the ability to meet this goal without amending its plan, and for this reason, DEF does not join in the request to modify its 2016 Risk Management Plan.

[10]Staff notes that although a small portion of these hedges for 2018 and extending to future periods may have already been executed under the applicable 2016 Risk Management Plan, this proposed limitation only applies to the unhedged portions. The 2017 Risk Management Plans are due to be filed on August 4, 2016, in the Fuel Clause docket.

[11]The Petitioners individually requested confidential classification pursuant to Section 366.093, F.S., and Rule 25-22.006, Florida Administrative Code.

The Petitioners also propose commitments regarding the time horizon over which hedges are placed. Generally speaking, the time horizon for hedging activities is a risk mitigation tool whereby the longer into the future that hedges are placed, the more price risk is attached. The opposite is true as well, and each Petitioner evaluates risk versus reward considerations in executing their hedging programs in a non-speculative, structured manner. The proposed commitments about time horizons varies by Petitioner.

Duration

In concert with their proposal to reduce hedging targets, TECO and Gulf commit to shortening their respective time horizons for hedging, contending that this strategy shift carries some risk. TECO currently hedges into a 24 month time frame, and is proposing to reduce that to an 18 month period. In its response to staff's first data request, TECO states that a 18 month window reduces the exposure to hedging losses during periods of declining natural gas prices, while still providing a measure of price stability, as well as some protection against price spikes. Gulf states that by reducing the time horizon for placing fixed priced swaps, the opportunity to lock in fixed prices in future years is diminished.

DEF and FPL acknowledge similar risk considerations, but do not propose specific commitments regarding the time horizon for placing hedges. DEF currently hedges into a rolling 36 month time frame, and acknowledges that with lowered targets in each rolling period, its customers will bear a greater portion of fuel cost risk. FPL states that its 2016 Risk Management Plan permits it to use hedging instruments for projected natural gas requirements up to, but not beyond, the end of the subsequent calendar year in which hedges are being placed (December 2017). Although FPL is proposing to modify its hedging targets, FPL is not proposing any changes to its time horizon for placing hedges.

Analysis

In the 2015 Fuel Order, the Commission approved the current (2016) Risk Management Plans each Petitioner filed, acknowledging, however, that the costs of the Petitioners' hedging programs is significant and deserves further analysis to consider methods to minimize potential losses to customers on a prospective basis.

The joint proposal the Petitioners are now advocating can reduce potential losses to be recovered from customers. Reducing the respective annual maximum percentage of fuel purchases targeted for hedges and shortening the period of time over which hedges may be placed pursuant to each respective Risk Management Plan continues the Commission's hedging objective, which is to reduce customers' exposure to price volatility. Imposing these limiting parameters will shield customers during times when uncertain market prices for natural gas are lower than hedged prices. On balance, however, because hedging volumes will be reduced, customers may experience less price stability, and if natural gas prices increase, customers may experience higher overall fuel costs.

Conclusion

Staff recommends the Commission approve the Joint Petition to modify the IOUs' Risk Management Plans.

Issue 2: Should this docket be closed?

Recommendation: If no protest is filed by a person whose substantial interests are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order. (Brownless)

Staff Analysis: If no protest is filed by a person whose substantial interests are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order.

Item 4

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

DB AA CRBB ALM

FROM: Division of Accounting and Finance (Buys, Archer, Bulecza-Banks, Cicchetti, Yeazel) SY
Office of the General Counsel (Leathers) MJ JC

RE: Docket No. 160006-WS – Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Section 367.081(4)(f), Florida Statutes (F.S.), authorizes the Commission to establish, not less than once each year, a leverage formula to calculate a reasonable range of returns on equity (ROE) for water and wastewater (WAW) utilities. The leverage formula methodology currently in use was established in Order No. PSC-01-2514-FOF-WS.[1] On October 23, 2008, the Commission held a formal hearing in Docket No. 080006-WS to allow interested parties to

[1] Order No. PSC-01-2514-FOF-WS, issued December 24, 2001, in Docket No. 010006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

provide testimony regarding the validity of the leverage formula.[2] Based on the record in that proceeding, the Commission approved the 2008 leverage formula in Order No. PSC-08-0846-FOF-WS.[3] In that order, the Commission reaffirmed the methodology that was previously approved in Order No. PSC-01-2514-FOF-WS.

Staff continues to use the leverage formula methodology established in Order No. PSC-01-2514-FOF-WS and reaffirmed in Order No. PSC-08-0846-FOF-WS. This methodology uses ROEs derived from financial models applied to an index of natural gas utilities. Based on the results of staff's annual review, there are an insufficient number of WAW utilities that meet the requisite criteria to assemble an appropriate proxy group using only WAW utilities. Therefore, since 2001, the Commission has used natural gas utilities as the proxy companies for the leverage formula. There are many natural gas utilities that have actively traded stocks and forecasted financial data. Staff uses natural gas utilities that derive at least 49 percent of their revenue from regulated rates. These utilities have market power and are influenced significantly by economic regulation. As explained in Issue 1, the model results based on natural gas utilities are adjusted to reflect the risks faced by Florida WAW utilities.

The Commission approved the current leverage formula in 2011 by Order No. PSC-11-0287-PAA-WS.[4] In 2012,[5] 2013,[6] 2014,[7] and 2015[8] the Commission approved staff's recommendations to continue to use the 2011 leverage formula for establishing the authorized ROE for WAW utilities. In 2012, 2013, 2014, and 2015, the Commission found that the range of returns on equity derived from the annual leverage formulas were not optimal for determining the appropriate authorized ROE for WAW utilities due to Federal Reserve monetary policies that resulted in historically low interest rates. Consequently, the Commission decided that the range of returns on equity of 8.74 percent to 11.16 percent from the 2011 leverage formula was more reasonable.

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[2] At the May 20, 2008, Commission Conference, upon request of the Office of Public Counsel, the Commission voted to set the establishment of the appropriate leverage formula directly for hearing.

[3] Order No. PSC-08-0846-FOF-WS, issued December 31, 2008, in Docket No. 080006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

[4] Order No. PSC-11-0287-PAA-WS, issued July 5, 2011, in Docket No. 110006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

[5] Order No. PSC-12-0339-PAA-WS, issued June 28, 2012, in Docket No. 120006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

[6] Order No. PSC-13-0241-PAA-WS, issued June 3, 2013, in Docket No. 130006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

[7] Order No. PSC-14-0272-PAA-WS, issued May 29, 2014, in Docket No. 140006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

[8] Order No. PSC-15-0259-PAA-WS, issued July 2, 2015, in Docket No. 150006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

Discussion of Issues

Issue 1: What is the appropriate range of returns on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), Florida Statutes?

Recommendation: Staff recommends that the current leverage formula approved by the Commission in Order No. PSC-15-0259-PAA-WS continue to be used until the leverage formula is readdressed in 2017. Accordingly, staff recommends the following leverage formula:

Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio)

Where the Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term and Short-Term Debt)

Range: 8.74% @ 100% equity to 11.16% @ 40% equity

Additionally, staff recommends that the Commission cap returns on common equity at 11.16 percent for all WAW utilities with equity ratios less than 40 percent. Staff believes this will discourage imprudent financial risk. This cap is consistent with the methodology in Order No. PSC-08-0846-FOF-WS. (Archer, Yeazel)

Staff Analysis: Section 367.081(4)(f), F.S., authorizes the Commission to establish a leverage formula to calculate a reasonable range of returns on common equity for WAW utilities. The Commission must establish this leverage formula not less than once a year. For administrative efficiency, the leverage formula is used to determine the appropriate return for an average Florida WAW utility. Traditionally, the Commission has applied the same leverage formula to all WAW utilities. As is the case with other regulated companies under the Commission's jurisdiction, the Commission has discretion in the determination of the appropriate ROE based on the evidentiary record in any proceeding. If one or more parties file testimony in opposition to the use of the leverage formula, the Commission will determine the appropriate ROE based on the evidentiary record in that proceeding.

Methodology

The leverage formula relies on two ROE models. Staff adjusts the results of these models to reflect differences in risk and debt cost between the index of companies used in the models and the average Florida WAW utility. Both models include a four percent adjustment for flotation costs. The models are as follows:

- A Discounted Cash Flow (DCF) model applied to an index of natural gas utilities that have publicly traded stock and are followed by the Value Line Investment Survey (Value Line). This DCF model is an annual model and uses prospective growth rates.

- The index consists of eight natural gas companies that derive at least 49 percent of their total revenue from gas distribution service. These companies have a median Standard and Poor's bond rating of A-.

- A Capital Asset Pricing Model (CAPM) using a market return for companies followed by Value Line, the average yield on the Treasury's long-term bonds projected by the Blue Chip Financial Forecasts, and the average beta for the index of natural gas utilities. The market return for the 2016 leverage formula was calculated using a quarterly DCF model with stock prices as of May 12, 2015.

Staff averages the indicated returns of the above models and adjusted the result as follows:

- A bond yield differential of 45 basis points is added to reflect the difference in yields between an A-/A3 rated bond, which is the median bond rating for the natural gas utility index, and a BBB-/Baa3 rated bond. Florida WAW utilities are assumed to be comparable to companies with the lowest investment grade bond rating, which is Baa3. This adjustment compensates for the difference between the credit quality of "A-" rated debt and the credit quality of the minimum investment grade rating.

- A private placement premium of 50 basis points is added to reflect the difference in yields on publicly traded debt and privately placed debt, which is illiquid. Investors require a premium for the lack of liquidity of privately placed debt.

- A small utility risk premium of 50 basis points is added because the average Florida WAW utility is too small to qualify for privately placed debt.

After the above adjustments, the resulting cost of equity estimate is included in the average capital structure for the natural gas utilities.

Staff notes that the leverage formula depends on four basic assumptions:

1) Business risk is similar for all WAW utilities;

2) The cost of equity is an exponential function of the equity ratio but a linear function of the debt to equity ratio over the relevant range;

3) The marginal weighted average cost of investor capital is constant over the equity ratio range of 40 percent to 100 percent; and

4) The debt cost rate at an assumed Moody's Baa3 bond rating, plus a 50 basis point private placement premium and a 50 basis point small utility risk premium, represents the average marginal cost of debt to a Florida WAW utility over an equity ratio range of 40 percent to 100 percent.

For these reasons, the leverage formula is assumed to be appropriate for the average Florida WAW utility.

Updated Leverage Formula

In the instant docket, staff updated the leverage formula using the most recent 2016 financial data and the Commission approved methodology. The derivation of the leverage formula using the current methodology with updated financial information is presented in Attachment 1 of this recommendation.

Using the updated financial data in the leverage formula decreases both the lower end of the current allowed ROE range by 111 basis points and the upper end of the range by 53 basis points. Overall, the spread between the range of returns on equity based on the updated leverage formula is 300 basis points (7.63 percent to 10.63 percent). In comparison, the spread in the range of returns on equity for the existing leverage formula is 242 basis points (8.74 percent to 11.16 percent). The 300 basis point spread reflected in the updated leverage formula is significantly greater than the 20-year average spread of 187 basis points.

The inflated ROE spread relative to the 2011 leverage formula is caused by the very low bond rates resulting from the Federal Reserve's various monetary policies and quantitative easing programs, which are largely still in effect. In its press release dated April 27, 2016, the Federal Reserve stated:[9]

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.
>
> In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

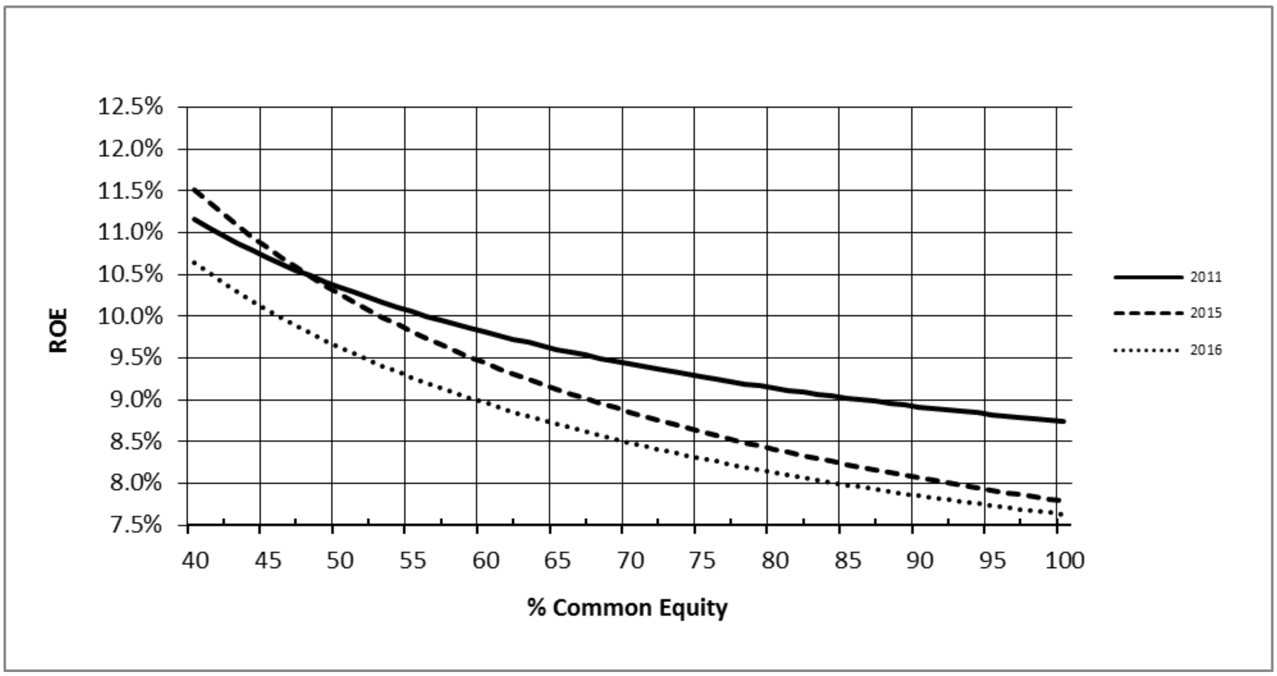
The most recent assumed Baa3 bond rate of 5.63 percent used in the updated leverage formula calculation, which includes a 50 basis point adjustment for small company risk and a 50 basis

[9] See Federal Reserve System, statement of the Federal Open Market Committee on April 26-27, 2016, available at https://www.federalreserve.gov/monetarypolicy/files/monetary20160427a1.pdf.

point adjustment for a private placement premium, remains low relative to historic levels. In comparison, the assumed Baa3 bond rate used in the existing leverage formula is 7.13 percent.

Because interest rates are at historically low levels, thereby increasing the slope of the leverage formula relative to prior years, staff believes the range of returns on equity produced from the updated leverage formula is not optimal for determining the appropriate authorized ROE for Florida WAW utilities at this time. An increase in the slope of the leverage formula means a given change in the equity ratio will result in a greater change to the cost of equity. The results of this year's leverage formula produced a slope consistent with the slopes produced by financial data for 2012 through 2015. As shown on the following page, Chart 1-1 illustrates the change in the slope of the 2016 leverage formula compared to the current leverage formula.

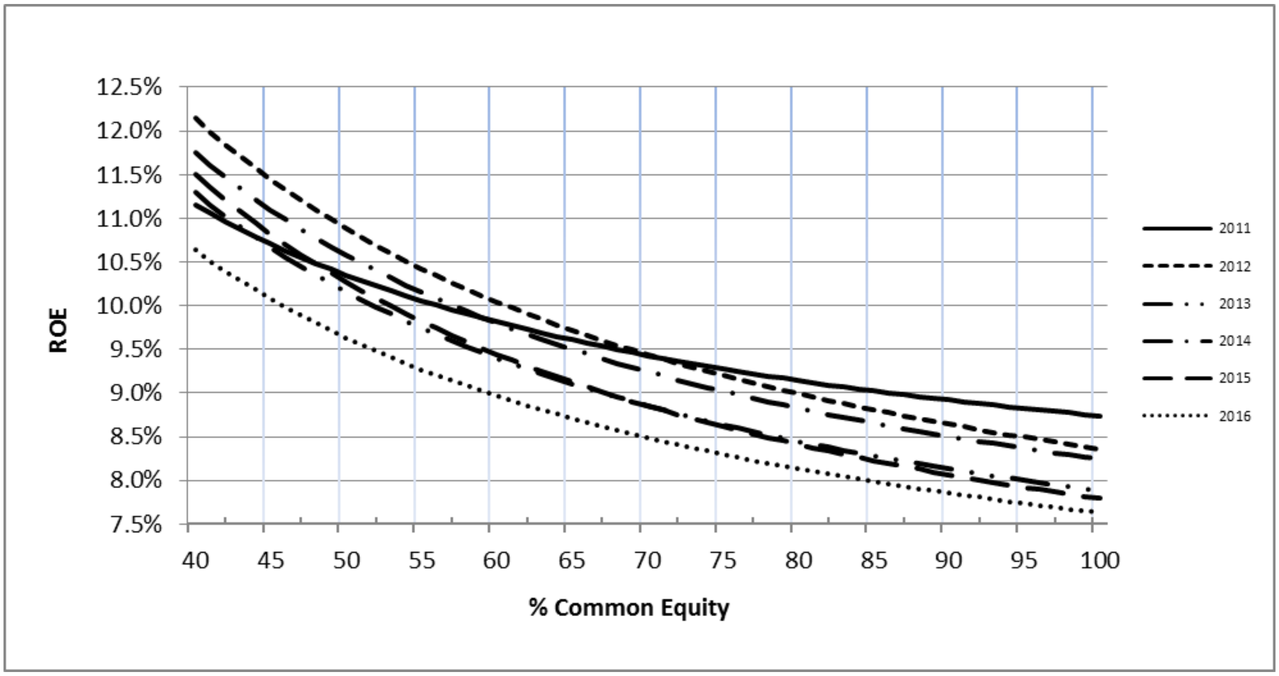
Chart 1-1
Comparison of Annual Leverage Formulas



Source: FPSC Staff Analysis

Chart 1-2 illustrates the change in the slope of the leverage formula for the six years 2011 through 2016.

Chart 1-2
Comparison of Annual Leverage Formulas since 2011



Source: FPSC Staff Analysis

In 2015, by Order No. PSC-15-0259-PAA-WS, the Commission approved staff's recommendation to continue to use the leverage formula initially approved in 2011. The Commission kept the 2011 leverage formula in place because Federal Reserve monetary policies lowered interest rates to historically low levels, thereby increasing the slope of the leverage formula graph relative to previous years. The Federal Reserve's monetary policies and resulting capital market conditions that existed in 2012 through 2015 are expected to continue in 2016.[10]

Although staff recommends the current leverage formula remain in place, staff has provided the updated leverage formula using the most recent financial information should the Commission decide to not continue to use the current in-place leverage formula and approve the updated leverage formula. In developing the leverage formula, staff used the same methodologies used in the 2011 docket. The updated model produced the following leverage formula:

Return on Common Equity = 5.63% + (2.001 ÷ Equity Ratio)

Where the Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term and Short-Term Debt)

Range: 7.63% @ 100% equity to 10.63% @ 40% equity

[10] Ibid.

In conjunction with the updated leverage formula, if the Commission decides to approve the updated leverage formula, the returns on common equity should be capped at 10.63 percent for all WAW utilities with equity ratios less than 40 percent to discourage imprudent financial risk. This cap is consistent with the methodology in Order No. PSC-08-0846-FOF-WS.

Conclusion

In staff's opinion, the existing leverage formula range of 8.74 percent to 11.16 percent initially approved in 2011 is still reasonable for WAW utilities. Staff believes retaining the use of the current in-place leverage formula until the leverage formula is addressed again in 2017 is a reasonable alternative to updating the formula using current 2016 financial information.

Staff continues to believe the leverage formula is a sound, workable methodology that reduces the costs and administrative burdens in WAW rate cases by eliminating the need for cost of equity testimony. Many of the WAW utilities under the Commission's jurisdiction are small operations that find it beneficial to avoid the costs associated with presenting cost of equity testimony.

Based on the aforementioned, staff recommends that the current leverage formula approved by the Commission in Order No. PSC-15-0259-PAA-WS continue to be used until the leverage formula is readdressed in 2017.

Issue 2: Should this docket be closed?

Recommendation: No. Upon expiration of the protest period, if a timely protest is not received from a substantially affected person, the decision should become final and effective upon the issuance of a Consummating Order. However, this docket should remain open to allow staff to monitor changes in capital market conditions and to readdress the reasonableness of the leverage formula as conditions warrant. (Leathers)

Staff Analysis: Upon expiration of the protest period, if a timely protest is not received from a substantially affected person, the decision should become final and effective upon the issuance of a Consummating Order. However, this docket should remain open to allow staff to monitor changes in capital market conditions and to readdress the reasonableness of the leverage formula as conditions warrant.

SUMMARY OF LEVERAGE FORMULA RESULTS

	Updated Results (2016)	Currently in Effect (2011)
(A) DCF ROE for Natural Gas Utility Index	7.62%	8.25%
(B) CAPM ROE for Natural Gas Utility Index	9.39%	9.40%
AVERAGE	8.51%	8.83%
Bond Yield Differential	0.45%	0.57%
Private Placement Premium	0.50%	0.50%
Small-Utility Risk Premium	0.50%	0.50%
Adjustment to Reflect ROE at 40% Equity Ratio	0.67%	0.76%
Cost of Equity for Average Florida WAW Utility with a capital structure containing a 40% Equity Ratio	10.63%	11.16%

2011 Leverage Formula (Currently in Effect)
Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio)
Range of Returns on Equity (100% to 40%) = 8.74% to 11.16%

2016 Leverage Formula (Using Current Data)
Return on Common Equity = 5.63% + (2.011 ÷ Equity Ratio)
Range of Returns on Equity (100% to 40%) = 7.63% to 10.63%

MARGINAL COST OF INVESTOR CAPITAL
(2016 Leverage Formula Result)

Average Marginal Cost Rate of the Natural Gas Utility Index

Capital Component	Ratio	Marginal Cost Rate	Weighted Marginal Cost Rate
Common Equity	46.22%	9.96%	4.60%
Total Debt	53.78%	5.63% *	3.03%
	100.0%		7.63%

Average Marginal Cost Rate at a 40% Equity Ratio

A 40% equity ratio is the floor for calculating the required return on common equity. The return on equity at a 40% equity ratio is 5.63% + (2.001 ÷ 0.40) = 10.63%

Capital Component	Ratio	Marginal Cost Rate	Weighted Marginal Cost Rate
Common Equity	40.00%	10.63%	4.25%
Total Debt	60.00%	5.63%*	3.38%
	100.00%		7.63%

Common Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term Debt + Short-Term Debt)

*Assumed 120-month average Baa3 rate as of April 2016 (4.63%) plus a 50 basis point private placement premium and a 50 basis point small utility risk premium.

Sources: Moody's Credit Perspectives and Value Line Selection and Opinion

ANNUAL DISCOUNTED CASH FLOW MODEL

NATURAL GAS UTILITY INDEX										STOCK PRICE APRIL 1, 2016 - APRIL 30, 2016		
COMPANY	DIV0	DIV1	DIV2	DIV3	DIV4	EPS4	ROE4	GR1-4	GR4+	HI-PR	LO-PR	AVG-PR
AGL RESOURCES INC.	2.12	2.16	2.24	2.32	2.40	4.65	11.50	1.0357	1.0556	65.95	64.71	65.330
ATMOS ENERGY CORPORATION	1.68	1.80	1.91	2.03	2.20	4.00	11.00	1.0610	1.0509	74.86	70.41	72.635
LACLEDE GROUP, INC.	1.92	1.96	2.04	2.12	2.20	4.20	9.50	1.0393	1.0452	68.40	62.65	65.525
NORTHWEST NATURAL GAS CO.	1.87	1.91	1.96	2.00	2.05	3.15	9.00	1.0239	1.0314	54.29	49.46	51.875
PIEDMONT NATURAL GAS CO., INC.	1.35	1.39	1.43	1.47	1.51	2.20	10.50	1.0280	1.0329	60.00	59.43	59.715
SOUTH JERSEY INDUSTRIES, INC.	1.08	1.15	1.23	1.31	1.40	2.20	11.50	1.0678	1.0418	28.55	27.17	27.860
SOUTHWEST GAS CORPORATION	1.80	1.92	2.04	2.17	2.30	4.80	13.00	1.0620	1.0677	66.60	62.75	64.675
WGL HOLDINGS, INC.	1.87	1.93	1.96	2.00	2.03	3.55	11.00	1.0170	1.0471	72.84	65.00	68.920
AVERAGE	1.7113	1.7775	1.8498	1.9256	2.0050	3.5938	10.8750	1.0418	1.0466			59.5669
					2.0984		Stock price including a four percent flotation cost:					**57.1842**
		Annual DCF Result:		**7.62%**								

Cash Flows	1.6055	1.5503	1.4992	1.4503	1.4050	49.6739
Present Value of Cash Flows	57.1842					

NOTE: The cash flows for this multi-stage DCF Model are derived using the average forecasted dividends and the near term and long term growth rates. The discount rate equates the cash flows with the average stock price less flotation cost.
$57.184 = Average stock price from April 1, 2015, through April 30, 2016, with a 4 percent flotation cost.
7.62% = Cost of equity required to match the current stock price with the expected cash flows.
Sources:
1. Stock Prices - Yahoo Finance.
2. Dividends (DIV), Dividends Per Share (DPS), Earnings Per Share (EPS), ROE - Value Line Ratings and Reports issued March 4, 2016.

CAPITAL ASSET PRICING MODEL

CAPM Analysis Formula

K = RF + Beta(MR - RF)

K = Investor's required rate of return

RF = Risk-free rate (Blue Chip forecast for Long-term Treasury bond, May 1, 2016)

Beta = Measure of industry-specific risk (Average for natural gas utilities followed by Value Line)

MR = Market return (Value Line Investment Analyzer Web Browser, as of May 12, 2016)

9.39% = 3.22% + 0.744(11.25% - 3.22%) + 0.20%

Note: Staff calculated the market return using a quarterly DCF model for a large number of dividend paying stocks followed by Value Line. As of May 12, 2016, the result was 11.25%. Staff also added 20 basis points to the CAPM result to allow for a four-percent flotation cost.

BONDYIELD DIFFERENTIALS

Public Utility Long Term Bond Yield Averages									
Month, Year	A2	Spread	A3	Spread	Baa1	Spread	Baa2	Spread	**Baa3**
April, 2016	3.970	0.170	4.140	0.170	4.310	0.170	4.480	0.170	4.650
120-Month Average							4.480	0.1509	**4.631%**
	-								
Sources: Moody's Credit Perspectives and Value Line Selection & Opinion									

UTILITY INDEX STATISTICS AND FACTS

Natural Gas Distribution Utility Companies	S&P Bond Rating	% of Gas Revenue	Value Line Market Capital (millions)	Equity Ratio	Value Line Beta
AGL Resources Inc.	BBB+	73%	$ 7,859.41	44.86%	0.60
Atmos Energy Corporation	A-	71%	$ 7,461.98	52.30%	0.80
Laclede Group, Inc.	A-	97%	$ 2,897.38	42.72%	0.70
Northwest Natural Gas Co.	A+	97%	$ 1,403.93	47.25%	0.65
Piedmont Natural Gas Co., Inc.	A	93%	$ 4,848.11	42.83%	0.75
South Jersey Industries, Inc.	BBB+	57%	$ 1,897.55	41.42%	0.85
Southwest Gas Corporation	BBB+	61%	$ 3,036.87	50.06%	0.80
WGL Holdings, Inc.	A+	49%	$ 3,421.07	48.33%	0.80
Average:	A-	75%	$ 4,103.29	46.22%	0.744

Sources:
Value Line Investment Analyzer Web Browser, May 2016
S.E.C. Forms 10Q and 10K for the natural gas utility companies
AUS Utilities Report, issued May, 2016
Standard & Poor's RatingsDirect

Item 5

FILED MAY 26, 2016
DOCUMENT NO. 03220-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Mtenga, King)
Division of Economics (Wu)
Office of the General Counsel (Murphy)

RE: Docket No. 160027-EI – Petition for approval of new environmental program for cost recovery through Environmental Cost Recovery Clause, by Tampa Electric Company.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On November 3, 2015, the Environmental Protection Agency (EPA) published its final rule titled Steam Electric Power Generating Effluent Limitations Guidelines (ELG).[1] The ELG establishes limits for wastewater discharges from flue gas desulfurization processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. The monthly averages and daily maximums will be exceeded under current processes at the Big Bend Station for arsenic, mercury and selenium. The effective date of the rule was January 4, 2016.

[1] 80 Fed. Reg. 67,838, 67,893 (Nov. 3, 2015) (to be codified at 40 CFR Part 423).

On February 2, 2016, Tampa Electric Company (TECO or Company) petitioned the Florida Public Service Commission (Commission) to approve the Big Bend Station Effluent Limitations Guidelines Compliance Study Program (Big Bend ELG Study Program) for cost recovery through the Environmental Cost Recovery Clause (ECRC). The Company intends to file for ELG cost recovery at their Polk Station at a later date. No objections to the petition have been received as of the filing of this recommendation.

By Section 366.8255, Florida Statutes (F.S.), the Florida Legislature authorized the recovery of prudently incurred environmental compliance costs through the ECRC. The method for cost recovery of such costs was first established by Order No. PSC-94-0044-FOF-EI, issued on January 12, 1994.[2] The Commission has jurisdiction over this matter pursuant to Section 366.8255, F.S.

[2]See Order No. PSC-94-0044-FOF-EI issued January 12, 1994, in Docket No. 930613-EI, *In re: Petition to establish an environmental cost recovery clause pursuant to Section 366.0825, Florida Statutes by Gulf Power Company.*

Discussion of Issues

Issue 1: Should the Commission approve Tampa Electric Company's petition for approval of a new environmental program for cost recovery through the Environmental Cost Recovery Clause?

Recommendation: Yes. Staff recommends that the Commission approve TECO's proposed Big Bend Station Effluent Limitations Guidelines Compliance Study Program for cost recovery through the Environmental Cost Recovery Clause. Staff recommends the O&M costs associated with this new environmental program be allocated to rate classes on an energy basis. (Mtenga)

Staff Analysis: The EPA's ELG rule establishes limits for wastewater discharges from flue gas desulfurization processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls.[3] TECO's facilities, including four coal-fired steam electric power generating units equipped with a flue gas desulfurization system located at the Big Bend Station, are affected by the ELG. The generating units' treatment system will need to be modified or replaced in order to achieve compliance with the new EPA regulations. The Company is proposing the Big Bend ELG Study Program to determine the most appropriate ELG compliance measures for the Big Bend Station. The measures selected in order to achieve ELG compliance will be the subject of a follow-up petition after completion of the Big Bend ELG Study Program and selection of the various compliance measures.

The activities planned by TECO for the Big Bend ELG Study Program include expenditures in 2016 to 2017. The expected scope of work for the study includes data review, site visits, design development, and technological evaluations including a conceptual design of selected alternatives. The estimated amounts for the Big Bend ELG Study Program are detailed in Table 1-1 below.

Table 1-1
Estimated Expenditures for Big Bend ELG Study Program

	Year	O&M Costs($)
Phase 1	2016	100,000
Phase 2	2017	300,000

Source: TECO's responses to staff's first data request No. 8 and TECO petition

TECO provided high level cost estimates based on experiences with previous studies and environmental compliance project management. Staff notes that the Company does not currently have a breakdown of the component activities.[4] Table 1-2 below, shows the estimated residential customer bill impacts resulting from the compliance study program.

[3] 80 Fed. Reg. 67,838, 67,893 (Nov. 3, 2015) (to be codified at 40 CFR Part 423).
[4] TECO's responses to staff's first data request No. 8.

Table 1-2
Estimated Residential Customer Bill Impacts

Year	¢/1,000 kWh	¢/ 1,200 kWh
2017	2.126	2.551
2018	0.000	0.000
2019	0.000	0.000

Source: TECO's response to staff's first data request No. 10

Based on the petition and TECO's responses to staff data requests, staff recommends that the proposed Big Bend ELG Study Program is necessary for compliance with the EPA's ELG rule.

The criteria for ECRC recovery relevant to this docket, established by Order No. PSC-94-0044-FOF-EI, are:

(1) The activities are legally required to comply with governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and

(2) None of the expenditures are being recovered through some other cost recovery mechanisms or through base rates.

Based on staff's analysis of the docket material, the activities proposed in TECO's petition meet these criteria. Staff recommends that, based on the information in the docket file and in the ELG rule, these activities are essential projects that would not be necessary but for TECO's obligation to comply with government-imposed environmental regulation.[5] The need for these compliance activities was triggered after TECO's last test year upon which rates are currently based.[6] Finally, the costs of the proposed compliance study activities are not currently being recovered through some other cost recovery mechanisms or through base rates.

Staff notes that the resonanableness and prudence of the individual expenditures related to TECO's Big Bend ELG Study Program will continue to be subject to the Commission's review in future ECRC proceedings.

Conclusion

Staff recommends that the Commission approve TECO's proposed Big Bend ELG Study Program for cost recovery through the ECRC. Staff recommends the O&M costs associated with this new environmental program be allocated to rate classes based on energy basis.

[5]40 C.F.R Part 423.11(n).
[6]See Order No. PSC-13-0443-FOF-EI issued September 20, 2013, in Docket 130040-EI, *In re: Petition for rate increase by Tampa Electric Company.*

Issue 2: Should this docket be closed?

Recommendation: Yes. This docket should be closed upon issuance of a Consummating Order unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the proposed agency action. (Murphy)

Staff Analysis: If no timely protest to the proposed agency action is filed within 21 days, this docket should be closed upon issuance of a Consummating Order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the proposed agency action.

Item 6

FILED MAY 26, 2016
DOCUMENT NO. 03228-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

Capital Circle Office Center • 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Lee)
Office of the General Counsel (Lherisson)

RE: Docket No. 160069-EQ – Petition for approval of revisions to rate schedule COG-2 for the standard offer, by Tampa Electric Company.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: ~~Administrative~~ Edgar

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: Staff recommends the Commission simultaneously consider Docket Nos. 160069-EQ, 160072-EQ, and 160073-EQ

Case Background

Section 366.91(3), Florida Statutes (F.S.), requires that each investor-owned utility (IOU) continuously offers to purchase capacity and energy from renewable energy generators. Florida Public Service Commission (Commission) Rules 25-17.200 through 25-17.310, Florida Administrative Code (F.A.C.), implement the statute and require each IOU to file with the Commission by April 1 of each year, a standard offer contract based on the next avoidable fossil fueled generating unit of each technology type identified in the utility's current Ten-Year Site Plan. On April 1, 2016, Tampa Electric Company (TECO) filed a petition for approval of its standard offer contract and associated rate schedule COG-2 based on its 2016 Ten-Year Site Plan. The Commission has jurisdiction over this standard offer contract pursuant to Sections 366.04 through 366.06 and 366.91, F.S.

Discussion of Issues

Issue 1: Should the Commission approve the revised standard offer contract and schedule COG-2 filed by Tampa Electric Company?

Recommendation: Yes. The provisions of TECO's revised schedule COG-2 for the standard offer contract conform to all requirements of Rules 25-17.200 through 25-17.310, F.A.C. TECO's revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation may select the payment stream best suited to its financial needs. (Lee)

Staff Analysis: Rule 25-17.250, F.A.C., requires that TECO, an IOU, continuously make available a standard offer contract for the purchase of firm capacity and energy from renewable generating facilities (RF) and small qualifying facilities (QF) with design capacities of 100 kilowatt (kW) or less. Pursuant to Rule 25-17.250(1) and (3), F.A.C., the standard offer contract must provide a term of at least 10 years, and the payment terms must be based on the utility's next avoidable fossil-fueled generating unit as identified in its most recent Ten-Year Site Plan, or if no avoided unit is identified, its next avoidable planned purchase.

TECO has identified a 220 megawatt (MW) natural gas-fired combustion turbine as its next avoidable fossil-fueled generating unit in its 2016 Ten-Year Site Plan. The projected in-service date of the unit is May 1, 2020.

The RF/QF operator may elect to make no commitment as to the quantity or timing of its deliveries to TECO, and to have a committed capacity of zero (0) MW. Under such a scenario, the energy is delivered on an as-available basis and the operator receives only an energy payment. Alternatively, the RF/QF operator may elect to commit to certain minimum performance requirements based on the identified avoided unit, such as being operational and delivering the agreed upon amount of capacity by the in-service date of the avoided unit, and thereby becomes eligible for capacity payments in addition to payments received for energy. The standard offer contract may also serve as a starting point for negotiation of contract terms by providing payment information to an RF/QF operator, in a situation where one or both parties desire particular contract terms other than those established in the standard offer.

In order to promote renewable generation, the Commission requires an IOU to offer multiple options for capacity payments, including the options to receive early or levelized payments. If the RF/QF operator elects to receive capacity payments under the normal or levelized contract options, it will receive as-available energy payments only until the in-service date of the avoided unit (in this case, May 1, 2020), and thereafter will receive capacity payments in addition to the energy payments. If either the early or levelized option is selected, then the operator will begin to receive capacity payments earlier than the in-service date of the avoided unit. However, payments made under the early capacity payment option tend to be lower in the later years of the contract term because the net present value (NPV) of the total payments must remain equal for all contract payment options.

Table 1 below estimates the annual payments for each payment option available under the revised standard offer contract to an operator with a 50 MW facility, operating at a 90 percent capacity factor, which is the minimum capacity factor required to qualify for full capacity payments. Normal and levelized capacity payments begin 2020, reflecting the projected in-service date of the avoided unit (May 1, 2020).

Table 1-Estimated Annual Payments to a 50 MW Renewable Facility (90% Capacity Factor)

Year	Energy Payment	Capacity Payment (By Type)			
		Normal	Levelized	Early	Early Levelized
	$(000)	$(000)	$(000)	$(000)	$(000)
2017	10,372	0	0	2,725	3,198
2018	11,101	0	0	2,792	3,209
2019	11,770	0	0	2,862	3,220
2020	13,625	2,562	2,937	2,933	3,232
2021	12,955	2,626	2,948	3,005	3,244
2022	13,940	2,691	2,958	3,080	3,257
2023	15,560	2,758	2,969	3,157	3,269
2024	17,670	2,826	2,981	3,235	3,282
2025	17,108	2,896	2,992	3,315	3,295
2026	17,309	2,968	3,004	3,398	3,309
2027	18,404	3,042	3,016	3,482	3,323
2028	22,172	3,117	3,029	3,568	3,337
2029	21,170	3,195	3,042	3,657	3,351
2030	21,797	3,274	3,055	3,748	3,366
2031	24,950	3,355	3,068	3,841	3,382
2032	23,237	3,439	3,082	3,936	3,397
2033	27,033	3,524	3,096	4,034	3,413
2034	28,671	3,612	3,110	4,134	3,430
2035	29,198	3,701	3,125	4,237	3,446
2036	27,930	3,793	3,140	4,342	3,464
Total	385,971	53,380	51,550	69,479	66,425
NPV (2017$)	194,138	37,369	37,369	37,369	37,369

TECO's revised tariff sheets for the standard offer contract, in type-and-strike format, are included in Attachment A. All of the changes made to the tariff sheets are consistent with the updated avoided unit. Revisions include updates to the avoided unit, dates, and payment information which reflect the current economic and financial assumptions for the avoided unit.

Conclusion

The provisions of TECO's revised schedule COG-2 for the standard offer contract conform to all of the requirements of Rules 25-17.200 through 25-17.310, F.A.C. The revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation may select the payment stream best suited to its financial needs. Staff recommends that TECO's revised tariff sheets for the standard offer contract be approved as filed.

Issue 2: Should this docket be closed?

Recommendation: Yes. This docket should be closed upon issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, TECO's standard offer contract may subsequently be revised. (Lherisson)

Staff Analysis: This docket should be closed upon the issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, TECO's standard offer contract may subsequently be revised.

Standard Offer Contract (Schedule COG-2)

Tampa Electric Company

Revisions in underline and strike-through format
shown the following sheets:

8.010, 8.326, 8.406, 8.422, 8.424, 8.426, 8.427, 8.434, and 8.436

TAMPA ELECTRIC

~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 8.010
CANCELS ~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 8.010

COGENERATION and SMALL POWER PRODUCTION

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

FIFTH REVISED SHEET NO. 8.015
CANCELS FOURTH REVISED SHEET NO. 8.015

ISSUED BY: G.L. Gillette, President **DATE EFFECTIVE:** July 21, 2015

TECO
TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 8.020
CANCELS THIRD REVISED SHEET NO. 8.020

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE

COG-1, As-Available Energy

AVAILABLE

Tampa Electric Company will purchase energy offered by any Qualifying Facility irrespective of its location, which is directly or indirectly interconnected with the Company, under the provisions of this schedule or at contract negotiated rates. Tampa Electric Company will negotiate and may contract with a Qualifying Facility, irrespective of its location, which is directly or indirectly interconnected with the Company where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE

To any cogeneration, renewable energy, or small power production Qualifying Facility producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by the Florida Public Service Commission (FPSC) Rule 25-17.0825, Florida Administrative Code (F.A.C.), and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required. Because of the lack of assurance as to the quantity, time, or reliability of delivery of As-Available Energy, no Capacity Payment shall be made to a Qualifying Facility for delivery of As-Available Energy. Criteria for achieving Qualifying Facility status shall be those set out in FPSC Rule 25-17.080.

CHARACTER OF SERVICE

Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering As-Available Energy from the Qualifying Facility.

Continued to Sheet No. 8.030

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

Continued from Sheet No. 8.020

LIMITATIONS
All service pursuant to this schedule is subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

RATES FOR PURCHASES BY THE COMPANY

A. **Capacity Rates**
Capacity payments to Qualifying Facilities will not be paid under this schedule. Capacity payments to small Qualifying Facilities of less than 100 kWs or Solid Waste Facilities may be obtained under either a Standard Offer Contract as described in Schedule COG-2, Firm Capacity and Energy or a negotiated contract.

Capacity payments to Qualifying Facilities of 100 kWs or greater may only be obtained under a negotiated contract as described in FPSC Rule 25-17.0832.

B. **Energy Rates**
As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour (¢/KWH), based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C.

Avoided energy costs include incremental fuel and identifiable variable operation and maintenance expenses. The calculation of payments to the Qualifying Facility shall be based on the energy deliveries from the Qualifying Facility to the Company and the applicable avoided energy rate, in accordance with FPSC Rule 25-17.082, F.A.C. All sales shall be adjusted for losses reflecting delivery voltage.

The methodology to be used in the calculation of the avoided energy cost is described in Appendix A.

C. **Negotiated Rates**
Upon agreement by both the Company and the Qualifying Facility, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

Continued to Sheet No. 8.040

ISSUED BY: W. N. Cantrell, President

DATE EFFECTIVE: March 9, 2004

TAMPA ELECTRIC COMPANY **TWENTY-FIFTH REVISED SHEET NO. 8.040**
CANCELS TWENTY-FOURTH REVISED SHEET NO. 8.040

Continued from Sheet No. 8.030

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

Upon request by a qualifying facility or any interested person, the Company shall provide within 30 days its most current projections of its generation mix, fuel price by type of fuel, and at least a five year projection of fuel forecasts to estimate future as-available energy prices as well as any other information reasonably required by the qualifying facility to project future avoided cost prices including, but not limited to, a 24 hour advance forecast of hour-by-hour avoided energy costs. The Company may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

Continued to Sheet No. 8.050

ISSUED BY: J. B. Ramil, President **DATE EFFECTIVE:** March 30, 1999

TAMPA ELECTRIC

FIFTEENTH REVISED SHEET NO. 8.050
CANCELS FOURTEENTH REVISED SHEET NO. 8.050

Continued from Sheet No. 8.040

DELIVERY VOLTAGE ADJUSTMENT
For purchases from Qualifying Facilities directly interconnected to the Company, the Company's actual hourly avoided energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0534
GSD, SBF	1.0496
IS, SBI	1.0185

For purchases from Qualifying Facilities not directly interconnected to the Company, any adjustments to the Company's actual hourly avoided energy costs for delivery voltage will be determined based on the Company's current annual system average transmission loss factor.

METERING REQUIREMENTS
The Qualifying Facility within the territory served by the Company shall be required to purchase from the Company the metering equipment necessary to measure its energy deliveries to the Company. Energy purchased from Qualifying Facilities outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering As-Available Energy to the Company. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

Hourly recording meters shall be required for Qualifying Facilities with an installed capacity of 100 kilowatts or more. Where the installed capacity is less than 100 kilowatts, the Qualifying Facility may select any one of the following options: **(a)** an hourly recording meter, **(b)** a dual kilowatt-hour register time-of-day meter, or **(c)** a standard kilowatt-hour meter.

For Qualifying Facilities with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on the product of: **(1)** the Company's actual As-Available Energy Payment Rate for each hour during the month; and **(2)** the quantity of energy sold by the Qualifying Facility during that hour.

For Qualifying Facilities with dual kilowatt-hour register time-of-day meters, monthly payments for As-Available Energy shall be calculated based on the product of: **(1)** the average of the Company's actual hourly As-Available Energy Payment Rates for the on-peak and off-peak periods during the month; and **(2)** the quantity of energy sold by the Qualifying Facility during that period.

Continued to Sheet No. 8.060

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** December 31, 2015

Continued from Sheet No. 8.050

For Qualifying Facilities with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly As-Available Energy Payment Rate for the off-peak periods during that month; and (2) the quantity of energy sold by the Qualifying Facility during that month.

For a time-of-day metered Qualifying Facility, the on-peak hours occur Monday through Friday except holidays, April 1 - October 31 from 12 noon to 9:00 p.m. and November 1 - March 31 from 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.. All hours not mentioned above and all hours of the holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

BILLING OPTIONS
The Qualifying Facilities may elect to make either simultaneous purchases and sales or net sales. The billing option elected may only be changed in accordance with FPSC Rule 25-17.082:

1. when the Qualifying Facility selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or

2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the Qualifying Facility or Tampa Electric Company; or

3. when the Qualifying Facility is selling As-Available Energy and has not changed billing methods within the last twelve months; and

4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the Qualifying Facility and Tampa Electric Company.

If the Qualifying Facility elects to change billing methods in accordance with FPSC Rule 25-17.082, such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice;

Continued to Sheet No. 8.061

Continued from Sheet No. 8.060

2. upon the installation by Tampa Electric Company of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such metering equipment and its installation; and

3. upon completion and approval by Tampa Electric Company of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such alterations.

Should a Qualifying Facility elect to make simultaneous purchases and sales, purchases of electric service by the Qualifying Facility from the interconnecting utility shall be billed at the retail rate schedule under which the Qualifying Facility load would receive service as a customer of the utility; sales of electricity delivered by the Qualifying Facility to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

Should a Qualifying Facility elect a net billing arrangement, the hourly net energy sales delivered to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832, purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the QF load would receive service as a customer of the utility.

Continued to Sheet No. 8.070

TAMPA ELECTRIC

NINTH REVISED SHEET NO. 8.070
CANCELS EIGHTH REVISED SHEET NO. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.00	GST	20.00
GS	18.00	GSDT (secondary)	30.00
GSD (secondary)	30.00	GSDT (primary)	130.00
GSD (primary)	130.00	GSDT (subtrans.)	990.00
GSD (subtrans.)	990.00	SBFT (secondary)	55.00
SBF (secondary)	55.00	SBFT (primary)	155.00
SBF (primary)	155.00	SBFT (subtrans.)	1,015.00
SBF (subtrans.)	1,015.00	IST (primary)	622.00
IS (primary)	622.00	IST (subtrans.)	2,372.00
IS (subtrans.)	2,372.00		
SBI (primary)	647.00		
SBI (subtrans.)	2,397.00		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 20, 2014

Continued from Sheet No. 8.070

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection including the metering. The Qualifying Facility shall have the option of payment in full for interconnection or making equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

C. **Interconnection Charge for Variable Utility Expenses**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include: (a) the Company's inspections of the interconnection and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company are involved.

Continued to Sheet No. 8.080

Continued from Sheet No. 8.071

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility.

If the Company obtains any tax savings as a result of its purchases of As-Available Energy produced by the Qualifying Facility, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the Qualifying Facility.

TERMS OF SERVICE

1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in its electric generation capability.

2) Any electric service delivered by the Company to the Qualifying Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

   A) In the first year of operation, the security deposit shall be based upon the singular month in which the Qualifying Facility's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the Qualifying Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon interconnection.

   B) For each year thereafter, a review of the actual sales and purchases between the Qualifying Facility and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Qualifying Facility exceed the actual sales to the utility in that month.

Continued to Sheet No. 8.090

Continued from Sheet No. 8.080

4) The company shall specify the point of interconnection and voltage level.

5) The Company will, under the provisions of this schedule, require an interconnection agreement with the Qualifying Facility using either the Company's filed Interconnection Agreement or a negotiated Interconnection Agreement. The Qualifying Facility shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated, and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6) Service under this rate schedule is subject to the rules and regulations of the Company and the Florida Public Service Commission.

SPECIAL PROVISIONS

1) Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the Florida Public Service Commission.

2) In accordance with the provision in Rule 25-17.0883, the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charge, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers.

A determination of whether or not transmission service for self-service wheeling is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3) In accordance with FPSC Rule 25-17.0889, F.A.C., upon request by a Qualifying Facility, the Company shall provide transmission service in accordance with its Open Access Transmission Tariff to wheel As-Available Energy or Firm Capacity and Energy produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

Continued to Sheet No. 8.100

TAMPA ELECTRIC COMPANY

SEVENTH REVISED SHEET NO. 8.100
CANCELS SIXTH REVISED SHEET NO. 8.100

Continued from Sheet No. 8.090

4) The rates, terms, and conditions for any transmission and ancillary services provide to a Qualifying Facility shall be those approved by the Federal Energy Regulatory Commission (FERC) and contained in the Company's Open Access Transmission Tariff.

5) A Qualifying Facility may apply for transmission and ancillary services from the Company in accordance with the Company's Open Access Transmission Tariff. Requests for service must be submitted on the Company's Open Access Same-Time Information System ("OASIS"). The Company's contact person, phone number and address is posted and updated on the OASIS and can be viewed by the public on the Internet at the address: http://www.enx.com/FOA_Contacts. html. A copy of the Company's Open Access Transmission Tariff is also posted at the address: http://www.enx.com/FOA/teco_home.html.

6) If the Qualifying Facility is located outside of the Company's transmission area, then the Qualifying Facility must arrange for long term firm third-party transmission, ancillary services and an interconnection agreement on all necessary external transmission paths for the term of the contract.

7) The Company may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non-discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the Company's general body of retail and wholesale customers.

ISSUED BY: J. B. Ramil, President

DATE EFFECTIVE: March 30, 1999

TAMPA ELECTRIC

SIXTH REVISED SHEET NO. 8.101
CANCELS FIFTH REVISED SHEET NO. 8.101

METHODOLOGY TO BE USED IN THE CALCULATION OF AVOIDED ENERGY COST SCHEDULE COG-1 APPENDIX A

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No.891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum operating reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or
2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits 1-4.

Continued to Sheet No. 8.102

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

THIRD REVISED SHEET NO. 8.102
CANCELS SECOND REVISED SHEET NO. 8.102

Continued from Sheet No. 8.101

The as-available avoided energy cost, as determined by this methodology, is priced at a level not to exceed Tampa Electric's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

PARAMETERS FOR DETERMINING AS-AVAILABLE AVOIDED ENERGY COSTS

Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).
2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.
3. The fuel costs associated with each of Tampa Electric's units operating at their allocated level of generation are determined by using the individual units input/output equation, its heat rate performance factor, and the composite price of supplemental fuel.
4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.
5. The Company's total cost equals its own production cost (4. above), identified variable O&M, plus the cost of any off-system purchases to serve native load.
6. Native load includes all firm and non-firm retail load.
7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour.
8. Firm interchange sales are included in production cost calculations.

Continued to Sheet No. 8.103

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: July 13, 2010

TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 8.103
CANCELS THIRD REVISED SHEET NO. 8.103

Continued from Sheet No. 8.102

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less operating reserve requirements.

10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to Tampa Electric from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known as-available energy purchases for that hour.

SUPPLEMENTAL FUEL

The term "supplemental fuel" refers to the variable cost for additional fuel to be delivered to Tampa Electric's generation facilities. The supplemental fuel price includes the cost of the fuel commodity at market prices plus the variable cost to deliver the commodity to the generation facility. Market prices for coal, oil and natural gas are based on published indexes or current market activity for commodities of comparable quality to those used in Tampa Electric's generation facilities.

Continued to Sheet No. 8.104

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 25, 2013

TAMPA ELECTRIC

THIRD REVISED SHEET NO. 8.104
CANCELS SECOND REVISED SHEET NO. 8.104

Continued from Sheet No. 8.103

AVOIDED ENERGY COST CALCULATIONS

Example 1: No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour-by-hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to TEC from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit 1.

Continued to Sheet No. 8.105

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

THIRD REVISED SHEET NO. 8.105
CANCELS SECOND REVISED SHEET NO. 8.105

Continued from Sheet No. 8.104

Example 2: Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit 2.

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit 3.

Example 3: Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit 4.

DELIVERY VOLTAGE ADJUSTMENT

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the adjustment factors shown on Sheet No. 8.050 for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based on the appropriate classification of service.

Continued to Sheet No. 8.106

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC COMPANY

SECOND REVISED SHEET NO. 8.106
CANCELS FIRST SHEET NO. 8.106

Continued from Sheet No. 8.105

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0561

The Actual Incremental hourly avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to Tampa Electric would then become, in this example, $15.63/MWH.

"IDENTIFIABLE" INCREMENTAL VARIABLE O&M

Tampa Electric's methodology for determining incremental avoided energy costs associated with as-available energy includes a procedure for calculating "identifiable" incremental variable O&M (VOM) expense.

A VOM rate ($/MWH) is calculated annually for each Tampa Electric generating group. A generating group comprises units of the same type with similar size and operating characteristics (e.g., Big Bend coal units, Bayside CCs, Polk IGCC, all 180 MW CTs, etc.). The VOM rate for a generating group is calculated by dividing the previous year's identifiable VOM expenses for the group by the previous year's generation in megawatt-hours for the group.

The incremental avoided energy cost associated with as-available energy is adjusted in each hour by the applicable VOM group rate(s) for the generation being avoided in that hour.

Continued to Sheet No. 8.107

ISSUED BY: W. N. Cantrell, President

DATE EFFECTIVE: March 9, 2004

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TAMPA ELECTRIC

THIRD REVISED SHEET NO. 8.109
CANCELS SECOND REVISED SHEET NO. 8.109

Continued from Sheet No. 8.107

EXHIBIT 1

Example: **No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):
Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):
Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost =
($20,275/Hour - $19,500/Hour) / (50MW)
or
As-Available Energy Payment Rate (AEPR) = $15.50/MWH

Continued to Sheet No. 8.110

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

SEVENTH REVISED SHEET NO. 8.110
CANCELS SIXTH REVISED SHEET NO. 8.110

Continued from Sheet No. 8.109

EXHIBIT 2

Example: **Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:
Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:
Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda1) =
($18,900/Hour - $18,882.50/Hour) / (1 MW)
or
As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:
1 In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.111

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

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FOURTH REVISED SHEET NO. 8.111
CANCELS THIRD REVISED SHEET NO. 8.111

Continued from Sheet No. 8.110

EXHIBIT 3

Example: **Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1530 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 1 0 MWs

Step 1 (Calculations for First 30 MWs)
First Calculation ("WITHOUT" QF):
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation ("With" QF):
Production Cost at 1500 MWs = $20,050/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)
First Calculation:
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda [1]) for 20 MWs=
($20,590/Hour- $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)
Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
($540 + $370)/ 50 MW

or

As-Available Energy Payment Rate (AEPR) = $18.20/MWH

Note: [1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.112

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

THIRD REVISED SHEET NO. 8.112
CANCELS SECOND REVISED SHEET NO. 8.112

Continued from Sheet No. 8.111

EXHIBIT 4

Example: **Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases1 = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AEPR = $40/Hour

NOTE:

1 Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

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TAMPA ELECTRIC COMPANY

SECOND REVISED SHEET NO. 8.114
CANCELS FIRST SHEET NO. 8.114

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ISSUED BY: W. N. Cantrell, President

DATE EFFECTIVE: March 9, 2004

STANDARD OFFER CONTRACT FOR THE PURCHASE OF CONTRACTED CAPACITY AND ASSOCIATED ENERGY FROM A RENEWABLE GENERATING FACILITY OR A SMALL QUALIFYING FACILITY

This standard offer contract ("Contract") is made and entered into this ___ day of _________, ______ by and between ____________________, the owner and/or operator of a Facility, as defined below, hereinafter referred to as the "Capacity and Energy Provider" or "CEP" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida (hereinafter referred to as the "Company"). The following documents are attached to this Contract and incorporated herein by reference: Appendix I, Evaluation Procedure for Standard Offer Contracts; Appendix II, COG -2 Standard Offer Contract Rate for Purchase of Contracted Capacity and Associated Energy, including all attached appendices thereto; and Appendix III, Interconnection Agreement. The CEP and the Company are also identified hereinafter individually, as a "Party" and collectively, as the "Parties". This Contract may also be referred to herein as the "Standard Offer Contract."

WITNESSETH:

WHEREAS, the CEP is the owner and/or operator of a Facility; and

WHEREAS, the CEP desires to sell Contracted Capacity and Associated Energy, as those terms are defined below; and

WHEREAS, the Company desires to purchase Contracted Capacity and Associated Energy in accordance with Chapter 366.91 F.S. and Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.310, Florida Administrative Code (F.A.C.) and the Company's Rate Schedule COG-2; and

WHEREAS, the CEP has signed an Interconnection Agreement with the transmission service provider that serves the CEP's Facility, as defined below; and

WHEREAS, such Interconnection Agreement is attached and incorporated hereto as Appendix III; and

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FIRST REVISED SHEET NO. 8.204
CANCELS ORIGINAL SHEET NO. 8.204

WHEREAS, the Florida Public Service Commission ("FPSC") has approved the form of this Contract for the purchase of Contracted Capacity and Associated Energy from the CEP;

NOW, THEREFORE, in consideration of the mutual covenants and promises set forth herein and other good and valuable considerations the receipt and adequacy of which are hereby acknowledged, the Parties agree as follows:

1. **Definitions:**

   a. **Actual Capacity:** "Actual Capacity" shall mean the amount of Anticipated Capacity, as defined below, that can be made available to the Company at the Delivery Point and which the CEP has confirmed: (1) through performance testing prior to the Commercial In-Service Date, as defined below: and (2) at any time thereafter upon the Company's request.

   b. **Anticipated Capacity:** "Anticipated Capacity" shall mean the amount of capacity that the CEP intends to make available to the Company at the Delivery Point in ____________ kW or in ___________ MW from the Facility beginning on or before _______________, the in-service date of the Designated Avoided Unit, as defined below.

   c. **Associated Energy:** "Associated Energy" shall mean the energy generated at the Facility, as defined below, by the generating source designated to supply Contracted Capacity and which is delivered to the Company at the Delivery Point, as defined below.

   d. **Company Transmission Service:** "Company Transmission Service" shall mean the network transmission service required through the Company's transmission system to deliver Associated Energy from the Delivery Point to the Company's native load customers.

   e. **Construction Commencement Date:** "Construction Commencement Date" shall mean the date on which the CEP's: (1) on-site activity is coordinated and continuous; and (2) active construction efforts are undertaken and on-going relative to the actual construction of major project features other than site preparation work; provided, however, that such date shall occur no later than _________________.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

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FIRST REVISED SHEET NO. 8.206
CANCELS ORIGINAL SHEET NO. 8.206

f. **Contracted Capacity:** "Contracted Capacity" shall mean the amount of Actual Capacity in ________ kW or in ________ MW that the CEP commits to reserve, make available and supply to the Company from its Facility on a firm, first-call, subordinate-to-no-other-entity-or-party, on-call, as-needed basis, and for which the Company commits to pay the CEP.

g. **Delivery Point:** "Delivery Point" shall mean: (1) the Interconnection Point, as described below, if the Facility is directly interconnected to the Company's transmission system; or (2) a point on the Company's transmission system, mutually agreed to by the Parties, at which the CEP shall deliver Contracted Capacity and Associated Energy via a third-party transmission service provider, if the Facility is not directly interconnected to the Company's transmission system.

h. **Designated Avoided Unit:** "Designated Avoided Unit." shall mean the generating unit, from among those units identified in the Appendices C through F to the Company's COG-2 Tariff as the Company's avoided units, selected by the CEP as the unit the CEP wishes to help avoid, or defer, and upon which capacity and energy payments to the CEP will be based. The CEP selects the Designated Avoided Unit from Appendix _____ of Rate Schedule COG-2.

i. **Eastern Prevailing Time:** "Eastern Prevailing Time" or "EPT" shall mean the time in effect in the Eastern Time Zone of the United States of America, whether Eastern Standard Time or Eastern Daylight Time.

j. **Evaluation Procedure:** "Evaluation Procedure" shall mean the procedure used by the Company to evaluate each eligible standard offer contract received by the Company as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2 The criteria used to evaluate standard offer contracts are attached hereto as Appendix I.

k. **Extended Facility In-Service Date:** "Extended Facility In-Service Date" shall mean an extension of the Facility In-Service Date, as defined below, for a period not to exceed five (5) months which may be granted in accordance with Section 7 below.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.208
CANCELS ORIGINAL SHEET NO. 8.208

l. **Facility**: "Facility" shall mean the CEP's proposed generating facility described in greater detail in Section 2, below.

m. **Facility In-Service Date:** "Facility In-Service Date" shall mean the date on which the Facility is available to supply Contracted Capacity and deliver Associated Energy to the Company (also referred to in the electric power industry as the commercial in-service date or commercial operation date).

n. **FERC:** "FERC" shall mean the Federal Energy Regulatory Commission or any similar or successor governmental body exercising the same or equivalent jurisdiction.

o. **Interconnection Point:** "Interconnection Point" shall mean the plant busbar connection to the high side of the Facility's step-up transformer(s) where Contract Capacity and Associated Energy shall be delivered to the transmission service provider that serves the Facility. The Interconnection Point shall be specified in detail in the Interconnection Agreement (see Appendix III).

p. **Non-Dispatched Capacity:** "Non-Dispatched Capacity" shall mean the amount of Contracted Capacity that the Company declines to schedule or request during any given hour, due to an emergency condition, or any other condition/reason. The Company shall adjust the Dispatch Schedule, as defined below, as soon as practical to reflect the amount of Non-Dispatched Capacity, or ignore scheduled capacity levels altogether (if conditions require immediate action to protect the integrity and/or reliability of the Company's generating system and/or transmission system); however, the Company shall make reasonable efforts to minimize departures from the Dispatch Schedule.

q. **Non-Dispatched Energy:** "Non-Dispatched Energy" shall mean the energy associated with Non-Dispatched Capacity and which the Company declines to accept during any given hour, due to an emergency condition, or any other condition/reason.

r. **Qualifying Facility:** "Qualifying Facility" shall mean a cogeneration facility, or small power production facility, that satisfies the definition of, and qualifies as, a Qualifying Facility in accordance with the provisions of Subpart B of Subchapter K, Part 292 of Chapter I, Title 18, Code of Federal Regulations (C.F.R.), promulgated by the FERC, as the same may be amended from time to time, and must be "new capacity" pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA), construction of which began on or after November 9, 1978.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.212
CANCELS ORIGINAL SHEET NO. 8.212

s. **Renewable Generating Facility:** "Renewable Generating Facility" shall mean a generating facility that satisfies the definition of, and qualifies as, a renewable generating facility in accordance with the provisions of Section 366.91, Florida Statutes and Rule 25-17.210 (1), F.A.C.

t. **Small Qualifying Facility:** "Small Qualifying Facility" shall mean a Qualifying Facility with a design capacity of 100 kW or less, as defined by subsection 25-17.080(3), F.A. C.

u. **Third-Party Transmission Services:** "Third-Party Transmission Services" shall mean the firm transmission service(s) and ancillary services required to deliver Contracted Capacity and Associated Energy from the Facility to the Company's transmission system if the Facility is not directly interconnected to the Company's transmission system.

2. **CEP's Proposed Facility**: The CEP contemplates installing and operating a Facility designed to produce a maximum of ______________ kilowatts (kW) to be located at ___________________, which shall be and remain the specific site of the Facility providing Contracted Capacity and Associated Energy under this Contract throughout the Term, as described below, of this Contract. The Facility is designed, operated and controlled to satisfy the interconnection requirements of the Company's transmission system or the third-party transmission service provider that serves the Facility, as applicable. The Facility shall: (a) satisfy the Company's Open Access Transmission Tariff ("OATT") requirements and/or all non-FERC jurisdictional interconnection and/or transmission service agreements required by the CEP to deliver Contracted Capacity and Associated Energy to the Company, as applicable, to be designated a Company network resource and receive network transmission service from the Company; (b) be fully dispatchable in the manner set forth in Appendix __ of Rate Schedule COG-2; and (c) be an existing Renewable Generating Facility or a Small Qualifying Facility or a Renewable Generating Facility or a Small Qualifying Facility that the CEP proposes to construct and operate.

3. **Term:** The "Term" of this Contract shall commence immediately upon its execution by the Parties and shall terminate at 12:01 A.M. on the later of: (a) the last day of the tenth year following the in-service date of the avoided unit, or (b)______________(a date selected by the CEP provided that such date is no later than the day after the last day of the life of the avoided unit identified in Section 1h above).

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.214
CANCELS ORIGINAL SHEET NO. 8.214

4. **Company's Capacity and Energy Purchase Commitment**: The Company agrees to purchase all Contracted Capacity and Associated Energy, excluding Non-Dispatched Energy, generated at the Facility and provided to the Company at the Delivery Point by the CEP pursuant to this Contract, excluding the amount of capacity and energy consumed by the Facility's station service equipment (such as generator auxiliaries, emissions control and monitoring equipment, fuel handling equipment, etc.) and all transmission system losses incurred by the CEP to effect delivery of Contracted Capacity and Associated Energy to the Delivery Point.

5. **Non-Dispatched Capacity and Non-Dispatched Energy Restriction:** To the extent that there is Non-Dispatched Capacity and Non-Dispatched Energy during a given hour, such Non-Dispatched Capacity and Non-Dispatched Energy shall not be made available or sold by the CEP, or otherwise used in any way or disposed of, without the Company's prior written consent.

6. **Responsibilities for Interconnection Service, Third-Party Transmission Service and Company Transmission Service:** It is the responsibility of the CEP to request and secure the required interconnection service from the transmission service provider that serves the CEP's Facility, whether a third-party transmission service provider or the Company transmission service provider. If the Facility is not located within the Company's transmission system, it is the responsibility of the CEP to request and secure the required third-party transmission service(s) required to deliver Contracted Capacity and Associated Energy to the Company's transmission system. It is the responsibility of the CEP to: (i) satisfy the third-party transmission provider's, or the Company's, OATT requirements and/or all non-FERC jurisdictional interconnection and/or transmission service agreements required by the CEP to deliver Contracted Capacity and Associated Energy to the Company, as applicable; (ii) arrange and pay to interconnect the Facility to the third-party transmission service provider; (iii) become and continue to be an eligible customer under the third-party transmission provider's OATT, or the Company's OATT, as applicable, during the Term; and (iv) request and purchase all required firm Third-Party Transmission Services and interconnection service, if applicable, in a timely manner to satisfy the provisions of this Contract.

   If the Facility is located within the Company's transmission system, it is the responsibility of the Company to request and secure the network transmission service required to deliver Contracted Capacity and Associated Energy from the Delivery Point to the Company's native load customers. It is the responsibility of the Company to request and secure network transmission service in a timely manner to satisfy the provisions of this Contract.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

SIXTEENTH REVISED SHEET NO. 8.215
CANCELS FIFTEENTH REVISED SHEET NO. 8.215

Continued from Sheet No. 8.214

7. **Extension of Facility In-Service Date:** The CEP may request and the Company may grant, at its sole discretion, an Extended Facility In-Service Date provided, however, that the CEP shall be subject to the applicable provisions of the Completion Security subsection of the Security Guarantees section of this Contract. If the Facility In-Service Date is delayed and an Extended Facility In-Service Date has not been granted, or the Extended Facility In-Service Date is not satisfied, the CEP shall be subject to the applicable provisions of the Completion Security subsection of the Security Guarantees section of this Contract, which may be requested by the CEP and may be granted by the Company, at its sole discretion.

8. **Billing Methodology**: The billing methodology applicable to the Company's purchase, and the CEP's sale, of Contract Capacity and Associated Energy pursuant to this Contract shall be: (i) (_______) Net Billing Arrangement; or (ii) (______) Simultaneous Purchase and Sale Arrangement, such purchases being arranged from the interconnecting utility and sales being made to the Company. Once made, the selection of a billing methodology may only be changed in accordance with FPSC Rule 25-17.082, F.A.C., and shall be in accordance with the following provisions:

   a. upon at least 30 days advance written notice to the Company; and

   b. upon installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology; and

   c. upon payment by the CEP for such metering equipment and its installation; and

   d. upon the Company's approval and completion of any alterations to the Interconnection Point that are reasonably required to effect the change in billing methodology and upon payment by the CEP for such alterations.

   The Parties agree that the CEP's obligation to generate and sell Contracted Capacity and Associated Energy from the Facility is subject to both scheduled and unscheduled outages of the Facility and the transmission service(s) required to effect delivery of same to the Delivery Point. Neither Party shall be required to compensate the other Party for Contracted Capacity and Associated Energy which from time to time may not be generated and sold by the CEP, or received and purchased by the Company, as a result of such scheduled and unscheduled outages. The Parties agree to use best efforts to minimize the duration of any scheduled or unscheduled outages which from time to time may interrupt the purchase and sale of Contracted Capacity and Associated Energy under this Contract.

Continued to Sheet No. 8.216

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.216
CANCELS FIRST REVISED SHEET NO. 8.216

Continued from Sheet No. 8.215

9. **Payment:**

a. **Associated Energy Payment:** The Company agrees to pay the CEP for Associate Energy delivered to the Company at the Delivery Point in accordance with the energy payment options, rates, and procedures contained in Rate Schedule COG-2 attached hereto as Appendix II.

i. **Standard Energy Payments:** Associated Energy payments made prior to ____________________, shall be based on the Company's actual avoided energy costs as defined in Appendix B of Rate Schedule COG-2.

Beginning ____________________, to the extent that the Designated Avoided Unit would have been operated had it been installed by the Company, the CEP's Associated Energy payments will be based on the Company's Designated Avoided Unit's energy costs as calculated in Appendix -__ of Rate Schedule COG-2, otherwise the CEP's Associated Energy payment will be based on the Company's actual avoided energy costs. The determination of which energy cost shall be applied will be made hourly.

ii. **Fixed Energy Payments:** The CEP does___ does not ___ request fixed Associated Energy payments as follows:

____Yes______No, as to Associated Energy payments made prior to ______________, which, if requested, shall be based on the Company's year-by-year projection of system incremental fuel costs prior to hourly economy energy sales to other utilities, based on normal weather and fuel market conditions, plus a fuel market volatility risk premium mutually agreed to by Tampa Electric and the CEP, which projected system incremental fuel costs will be provided by the Company within 30 days of the date of request by the CEP. The CEP and Tampa agree to the following fuel market volatility risk premium(s):_________________ .

______Yes_____No, as to Associated Energy payments, calculated as follows: Subsequent to the determination of full avoided cost and subject to the provisions of paragraphs 25-17.0823(3)(a) through (d) F.A.C., a portion of the base energy costs associated with the avoided unit, mutually agreed upon by the Company and the CEP, shall be fixed and amortized on a present value basis over this Contract commencing, at the election of the CEP, as early as the in-service date of the CEP's Facility. "Base energy costs associated with the avoided unit" means the energy costs

Continued to Sheet No. 8.218

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.218

of the avoided unit to the extent that the Designated Avoided Unit would have been operated.

The stream of Fixed Energy Payments to the CEP, calculated as stated above, will be provided by the Company within 30 days of the date of request by the CEP.

b. **Contracted Capacity Payment:**

i. **Dispatch Requirements:** In order to receive a Contracted Capacity Payment for each calendar month that the Facility is to be dispatched, the CEP must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

ii. **Commencement of Contracted Capacity Payments:** The CEP elects to receive, and the Company agrees to commence calculating, Contracted Capacity payments in accordance with this Contract starting with the first Monthly Period following ______________________.

iii. **Contracted Capacity Payment Options:** The following five (5) options are available to the CEP for payment of Contracted Capacity delivered by the CEP:

1. Value of Deferral Capacity Payments;
2. Early Capacity Payments;
3. Levelized Capacity Payments;
4. Early Levelized Capacity Payments; or
5. Other Contracted Capacity Payment Option agreed upon by the Parties that best satisfies the financing requirements of the Facility. Such Other Contracted Capacity Payment Option is described as follows:

____
____
____

The CEP elects to receive Contracted Capacity payments pursuant to option _______ above.

The CEP _____ does ___ does not elect to have Early Capacity Payments consisting of the capital component of the Company's Designated Avoided Unit commence on _____________ (a date any time after the actual Facility In-Service date and before the anticipated in-service date of the Company's Designated Avoided Unit).

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.222
CANCELS ORIGINAL SHEET NO. 8.222

Regardless of the Contracted Capacity Payment Option elected by the CEP, the cumulative present value of payments for the Contracted Capacity made to the CEP over the Term shall not exceed the cumulative present value of payments for the Contracted Capacity which would have been made to the CEP had such payments been made pursuant to subparagraph 25-17.0832(4)(g)1., F.A.C. All fixed operation and maintenance expense shall be calculated in conformance with subsection 25-17.0832(6), F.A.C.

At the end of each Monthly Period, beginning with the Monthly Period specified in Section 9.b.ii, the Company will calculate the CEP's Monthly Availability and Capacity Factor. During the Term, if the CEP's Monthly Availability and Capacity Factor equals or exceeds the Minimum Performance Standards (MPS) as set forth for in Rate Schedule COG-2, Appendix __, then the Company agrees to pay the CEP a Monthly Capacity Payment as calculated in paragraph 5 of the section entitled Basis for Monthly Capacity Payment Calculation in Appendix ___ of Rate Schedule COG-2.

The Contracted Capacity payment for a given month during the Term will be added to the Associated Energy payment for such month and tendered by the Company to the CEP as a single payment as promptly as possible, normally by the 20^{th} business day following the day the meter is read or the amount of Associated Energy delivered via the third-party transmission service provider is confirmed by the Company.

10. **Other Contracted Capacity Payment Security Guarantees:** If the CEP selects Option 5 under the Contracted Capacity Payment Options, the following security guarantees will be required: ____.

11. **Construction and Performance Security Guarantees:** The Company requires certain security guarantees to ensure the completion of construction and performance under this Contract in order to protect its ratepayers in the event the CEP fails to deliver Contracted Capacity and Associated Energy in the amount and times specified in this Contract, which shall be in form and substance as described herein. Such security may be refunded in the manner described in Sections 11.a. and 11.b. Pursuant to FPSC Rule 25-17.091, F.A.C., a utility may not require security guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832(2)(d) and (3)(f)(1), F.A.C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

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SECOND REVISED SHEET NO. 8.224
CANCELS FIRST REVISED SHEET NO. 8.224

Continued from Sheet No. 8.222

a. **Completion Security:** If the CEP or its guarantor, if any, does not qualify for unsecured credit in Company's reasonable sole discretion, the CEP shall pay to the Company a security deposit equal to $30.00 per kilowatt ($30.00/kW) of Contracted Capacity as security for the CEP's completion of the Facility by the Facility In-Service Date. Such security will be required within sixty (60) days of execution of this Contract. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the CEP; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the CEP fails to complete the construction and achieve commercial in-service status by the Facility In-Service Date.

If the Facility In-Service Date is achieved, then the entire deposit and any interest therein, if applicable, shall be refunded to the CEP upon payment by the CEP of the Performance Security as required in Section 11.b.

If the Facility In-Service Date is delayed, the Company may, upon the request of the CEP, at its sole discretion, agree to an Extended Facility In-Service Date, in which case the Company shall be entitled to retain or draw down on an amount equal to twenty percent (20%) of the original deposit amount for each month (or portion thereof) that the Facility In-Service Date is delayed. If the Facility In-Service Date is delayed and an Extended Facility In-Service Date has not been granted or the Extended Facility In-Service Date is not satisfied or delayed beyond the Extended Facility In-Service Date, the Company shall retain all of the deposit and terminate this Contract.

Notwithstanding the foregoing if the CEP does not satisfy the Construction Commencement Date or the Facility In-Service Date as defined in COG-2 in accordance with the terms and conditions of this Contract, this Contract shall be rendered of no force and effect, except for those provisions of this Agreement that provide the Company rights and remedies as against CEP because of its failure to meet the Construction Commencement Date or the Facility In-Service Date.

Continued to Sheet No. 8.226

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.226
CANCELS ORIGINAL SHEET NO. 8.226

b. **Performance Security:** Within 60 days after the later of the Facility In-Service Date or the in-service date of the Designated Avoided Unit, the CEP shall pay the Company a deposit in the amount of $30.00/kW of Contracted Capacity as security for the CEP's performance under this Contract. Such security deposit shall be provided in the same manner as the Completion Security deposit as described in Section 11.a. Such Performance Security shall be retained by the Company for 12 months from the later of the Facility In-Service Date or the in-service date of the Designated Avoided Unit.

If, at the end of the 12-month period so described, the Facility's 12-month average of each month's numerical value for both the monthly Availability Factor and the Monthly Capacity Factor meet the Minimum Performance Standards (MPS) for as set forth in Rate Schedule COG-2, Appendix __, then the CEP shall be entitled to a refund of such deposit. However, if at the end of the first 12-month period, the Facility's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor fail to meet the MPS, then the Company shall be entitled to retain or draw down 50% of such deposit and retain the remainder of the security for an additional 12-month period.

If, at the end of the 24th month, the Facility's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor again fail to achieve the MPS, for the most recent 12-month period, then the Company shall be entitled to retain the remainder of the security and to terminate this Contract. However, if at the end of the 24th month, the Facility's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS, for the most recent 12-month period, then the CEP shall be entitled to a refund of the remaining deposit.

For the purpose of this calculation, the 12-month average of a parameter shall be defined to equal the sum of each month's average numerical value for that parameter, for the most recent 12-month period, divided by 12.

12. **Liquidated Damages:** The Parties hereto agree that the Company would be substantially damaged in amounts that would be difficult or impossible to ascertain in the event that the CEP fails to satisfy the Facility In-Service Date or to provide a Facility which meets the MPS. In the event that the Company terminates this Contract for the CEP's failure to achieve the Facility In-Service Date or achieve the MPS once in service, the Company may retain all of the Completion or Performance Security as liquidated damages, not as penalty, in lieu of actual damages and the CEP hereby waives any defenses as to the validity of any such liquidated damages. In the event the

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.228
CANCELS ORIGINAL SHEET NO. 8.228

CEP defaults, it forfeits the aforesaid Completion or Performance Security. In addition thereto, the Company shall be entitled to pursue such equitable remedies against the CEP as may be available.

13. **Production and Maintenance Schedule:** During the Term, the CEP agrees to the following:

a. The CEP shall provide the Company in writing prior to April 1st of each calendar year an estimate of the amount of electricity to be generated by the CEP and delivered to the Company for each month of the following calendar year, including the time, duration and magnitude of any planned outages of the Facility or reductions to the amount of Contracted Capacity that the CPE can make available at the Delivery Point.

b. By July 1st of each calendar year, the Company shall notify the CEP in writing whether the requested scheduled maintenance period(s) for the Facility are acceptable. If the Company cannot accept any of the requested period(s), the Company shall advise the CEP of the time period closest to the requested period(s) when the outage(s) can be scheduled. The CEP shall only schedule outages during periods approved by the Company and such approval shall not be unreasonably withheld. Once the schedule has been established and approved, either Party requesting a subsequent change in such schedule, except when such event is due to Force Majeure, must obtain approval for such change from the other Party. Such approval shall not be unreasonably withheld or delayed.

c. During the Term, the CEP shall employ qualified personnel for managing, operating and maintaining the Facility and for coordinating such with the Company. The CEP shall ensure that operating personnel are on duty at all times, twenty-four (24) clock hours per calendar day and seven (7) calendar days per week. Additionally, during the Term, the CEP shall operate and maintain the Facility in such a manner as to ensure compliance with its obligations hereunder.

d. The Company shall not be obligated to purchase and may require curtailed or reduced deliveries of Associated Energy, to the extent necessary to maintain the reliability and integrity of any part of the Company's system, or if the Company determines that a failure to do so is likely to endanger life or property, or is likely to result in significant disruption of electric service to the Company's Customers. The Company shall give the CEP prior notice, if practicable, of its intent to refuse, curtail or reduce the Company's acceptance of Associated Energy pursuant to this subsection and will act to minimize the frequency and duration of such occurrences.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

e. The Company shall not be required to accept or purchase Associated Energy during any period in which, due to operational circumstances, acceptance or purchase of such Associated Energy would result in the Company's incurring costs greater than those which it would incur by generating an equal additional amount of energy with its own resources. The Company shall give the CEP as much prior notice as practicable of its intent not to accept Associated Energy pursuant to this subsection.

f. The CEP shall promptly update the yearly generation schedule and maintenance schedule of the Facility as soon as any change to such schedules are determined to be necessary;

g. The CEP shall comply with reasonable requirements of the Company regarding day-to-day or hour-by-hour communications between the Parties relative to the performance of this Contract.

14. **Dispatch Procedure**: Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 7:00 A.M. EPT, the CEP shall electronically transmit the hour-by-hour amounts of Contracted Capacity expected to be available from the Facility the next day ("Available Schedule"). Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 3:00 P.M. EPT, the Company shall electronically transmit the hour-by-hour amounts of Contracted Capacity that the Company desires the CEP to dispatch from the Facility the next day based on the Available Schedule supplied at 7:00 A.M. EPT by the CEP ("Dispatch Schedule"). The CEP's Available Schedule and the Company's Dispatch Schedule for Fridays will include Saturday, Sunday, and Monday schedules. The CEP's Available Schedule and the Company's Dispatch Schedule during holiday periods will be similarly adjusted to include the holiday period. The CEP shall control and operate the Facility in accordance with the Company's Dispatch Schedule.

From time to time, the Company may be required to adjust the Dispatch Schedule, as described in the definition of Non-Dispatched Capacity, and/or the CEP may be required to adjust the Dispatch Schedule due to an unscheduled or forced outage of all, or a portion of, the Facility; however, each Party shall make reasonable efforts to minimize departures from the Dispatch Schedule.

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.234
CANCELS ORIGINAL SHEET NO. 8.234

15. **Additional Criteria:** The CEP shall comply with the reasonable requests of the Company regarding daily or hourly communications. Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing during the Term:

a. The CEP shall provide monthly generation estimates for the Facility by December 1 for the next calendar year; and

b. The CEP shall promptly update its yearly generation schedule for the Facility when any changes are determined necessary; and

c. The CEP shall agree to reduce generation from the Facility or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and

d. The CEP shall coordinate scheduled outages of the Facility with the Company.

16. **Automatic Generation Control:** At the Company's discretion, the CEP will operate the Facility with Automatic Generation Control (AGC) equipment, speed governors, and voltage regulators in-service, except at such times when operational constraints of the equipment prevent AGC operation.

17. **CEP's Obligation if the CEP Receives Payments Pursuant to Contracted Capacity Payment Options 2, 3, 4, or 5:** The Parties recognize that Rule 25-17.0832, F. A. C., may require the repayment by the CEP of all, or a portion of any, Capacity Payments made to the CEP pursuant to Contracted Capacity Payment Options 2, 3, 4, or 5 of Section 9.b.iii if the CEP fails to perform pursuant to the terms and conditions of this Contract. To ensure that the CEP will satisfy its obligation to make any such repayments, the following provisions will apply:

The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the CEP to the Company. Amounts shall be added to the Repayment Account each month through______________, in the amount of the Company's payments to the CEP for capacity delivered prior to_______________. Beginning on _________________, the difference between the

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 8.236
CANCELS THIRD REVISED SHEET NO. 8.236

Continued from Sheet No. 8.234

Contracted Capacity payment made to the CEP and the "normal" Contracted Capacity payment calculated pursuant to Contracted Capacity payment option 1 (Value of Deferral Payments) in COG-2 will also be added each month to the Repayment Account, so long as the payment made to the CEP is greater than the monthly payment the CEP would have received if it had selected Contracted Capacity Payment Option 1 in Section 6.b.iii. The annual balance in the Repayment Account shall accrue interest at an annual rate of 7.95%.

Also beginning on ___________________, at such time that the Monthly Contracted Capacity Payment made to the CEP, pursuant to the Contracted Capacity Payment Option selected, is less than the "normal" Monthly Contracted Capacity Payment in Capacity Payment Option 1 in COG-2, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if Contracted Capacity payments had been calculated pursuant to Contracted Capacity Payment Option 1 in COG-2 and the CEP had elected to begin receiving Contracted Capacity payments on ________________, minus the Monthly Contracted Capacity Payment the Company makes to the CEP (assuming the MPS are met or exceeded), pursuant to the Contracted Capacity Payment Option chosen by the CEP in Section 6.b.ii.

The CEP shall owe the Company and be liable for the current balance in the Repayment Account. The Company agrees to notify the CEP monthly as to the current Repayment Account balance.

In the event of default by the CEP, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the Early Contracted Capacity Payments made to the CEP by the Company. The CEP's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the CEP's Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the CEP.

Continued to Sheet No. 8.238

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.238
CANCELS FIRST REVISED SHEET NO. 8.238

Prior to receipt of Contracted Capacity Payments pursuant to Contracted Capacity Payment Options 2, 3, 4, or 5, the CEP shall secure its obligation to repay any balance in the Repayment Account in the event the CEP defaults pursuant to this Contract. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the CEP; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the CEP. Florida Statute 377.709(4) requires the local government to refund Early Contracted Capacity Payments should a Municipal Solid Waste Facility owned, operated by or on the behalf of a local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

18. **Ownership and Offering For Sale of Renewable Energy Attributes**: A CEP that owns and/or operates a Renewable Generating Facility retains any and all rights to own and sell any and all environmental attributes associated with the electrical generation of such Renewable Generating Facility, including but not limited to any and all renewable energy certificates, "green tags", or other tradeable environmental interests (collectively "RECs"), of any description. In the event that the CEP decides to sell any such environmental attributes during the term of this Contract, the CEP shall provide notice to the Company of its intent to sell such environmental attributes and provide the Company a reasonable opportunity to offer to purchase such environmental attributes.

19. **Changes in Environmental and Governmental Regulations:** This Contract may be re-opened, at the election of either Party, as a result of new environmental and other regulatory requirements enacted during the Term that affect the Company's full avoided costs of the unit on which this Contract is based.

20. **Non-Performance Provisions:** The CEP shall not receive a Contracted Capacity payment during any month during the Term in which the CEP fails to meet the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit as defined in Rate Schedule COG-2, Appendix __. In addition, if for any month starting __________ _______________, the CEP fails to achieve the MPS, and the Monthly Contracted Capacity Payment that would have been made to the CEP pursuant

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: August 7, 2009

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.242
CANCELS FIRST REVISED SHEET NO. 8.242

Continued from Sheet No. 8.238

to the Contracted Capacity payment option selected is less than the "normal" Monthly Contracted Capacity Payment had the CEP selected Option 1, then the CEP shall be liable for and shall pay the Company an amount equal to the Early Payment Offset Amount for the month; provided, however, that such calculation shall assume that the CEP satisfied the MPS. Any payments thus required of the CEP shall be separately invoiced by the Company to Energy Provider after each month for which such payment is due and shall be paid by the CEP within twenty (20) business days after receipt of such invoice by the CEP. Such payment shall be debited from the Capacity Account as an Early Payment Offset Amount provided that any such payment will not exceed the current balance in the Capacity Account.

21. **Default:**

a. **Mandatory Default:** The CEP shall be in default under this Contract if it:

i. is dissolved (other than pursuant to a consolidation, amalgamation or merger); or

ii. becomes insolvent or is unable to pay its debts or fails or admits in writing its inability generally to pay its debts as they become due; or

iii. makes a general assignment, arrangement or composition with or for the benefit of its creditors; or

iv. institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors' rights, or a petition is presented for its winding-up or liquidation, and, in the case of any such proceeding or petition instituted or presented against it, such proceeding or petition (a) results in a judgment of insolvency or bankruptcy or the entry of an order for relief or the making of an order for its winding-up or liquidation or (b) is not dismissed, discharged, stayed or restrained in each case within 30 days of the institution or presentation thereof; or

v. seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for it or for all or substantially all its assets; or

Continued to Sheet No. 8.243

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.243

Continued from Sheet No. 8.242

vi. has a secured party take possession of all or substantially all its assets or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within 30 days thereafter; or

vii. fails to perform in accordance with Section 11.b.

viii. fails to maintain its status as a Renewable Energy Facility or small Qualifying Facility as required herein; or

ix. fails to achieve, on both accounts, a minimum Monthly Availability Factor of fifty percent (50%) and fails to achieve a minimum Monthly Capacity Factor of fifty percent, during the same month, for twelve (12) consecutive months starting .

b. **Optional Default:** The Company may declare the CEP to be in default if:

i. at any time prior to ____________, and after Monthly Contracted Capacity Payments have begun, the Company has sufficient reason to believe that the CEP is unable to deliver the entire amount of Contracted Capacity; or

ii. after Monthly Capacity Payments have begun, the CEP fails each month, for twenty-four (24) consecutive months, to meet the MPS; or

iii. the CEP refuses, is unable or anticipatorily breaches its obligation to deliver the entire amount of Contracted Capacity after __________________.

c. **Default Remedy:** In the event of default by the CEP, the total Repayment Account balance shall become due and payable within 20 business days of receipt of written notice, as reimbursement for the Early Capacity Payments made to the CEP by the Company. The CEP's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of this Contract. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the CEP.

Continued to Sheet No. 8.244

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

22. **General Provisions:**

a. **Permits:** The CEP hereby agrees to seek to obtain any and all governmental permits, certifications, or other authority the CEP is required to obtain as a prerequisite to engaging in the activities provided for in this Contract. The Company hereby agrees to seek to obtain, at the CEP's expense, any and all governmental permits, certifications or other authority the Company is required to obtain as a prerequisite to engaging in the activities described in this Contract

b. **Indemnification:** The Company and the CEP shall each be responsible for its own facilities in ensuring adequate safeguards for other Company customers, the Company and Energy Provider personnel and equipment, and for the protection of its own generating system. The Company and the CEP shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

   i. any act or omission by a Party or that Party's contractors, agents, servants and employees in connection with the installation or operation of that Party's generation system or the operation thereof in connection with the other Party's system; and

   ii. any defect in, failure of, or fault related to a Party's generation system; and

   iii. the negligence of a Party or negligence of that Party's contractors, agents servants and employees; and

   iv. any other event or act that is the result of, or proximately caused by a Party.

c. **Insurance:** The CEP shall deliver to the Company, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the CEP's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the CEP as named insured, and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this Contract arising out of the interconnection to the Facility, or caused by operation of any of the Facility's equipment or by the CEP's failure to maintain its equipment in satisfactory and safe operating condition.

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.246

i. In subsequent years, a certificate of insurance renewal must be provided annually to the Company indicating the CEP's continued coverage as described herein. Renewal certification shall be sent to:

   Tampa Electric Company
   c/o Director of Risk Management
   Tampa Electric Company
   702 North Franklin Street (33602)
   P. O. Box 111
   Tampa, FL 33601

ii. The policy providing such coverage shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if the CEP has insurance with limits greater than the minimum limits required herein, the CEP shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Contract.

iii. The above required policy shall be endorsed with a provision whereby the insurance company to notify the Company thirty (30) days prior to the effective date of any cancellation or material change in said policy.

iv. The CEP shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company or the Term if the Facility is not interconnected to the Company's transmission system.

d. **Force Majeure:** If either Party shall be unable, by reason of Force Majeure, to carry out its obligations under this Contract, either wholly or in part, the Party so failing shall give written notice and full particulars of such cause or causes to the other Party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended during the continuance of such hindrance, which, however, shall be remedied with all possible dispatch; and the obligations, terms and conditions of this Contract shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "Force Majeure" shall be taken to mean all acts of God, strikes, lockouts or other industrial disturbances at the manufacturing site of the major equipment components or the construction site, wars, blockades, insurrections, riots, arrests and restraints of rules

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

and people, explosions, fires, floods, lightning, wind, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however that no occurrence may be claimed to be a Force Majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the Party attempting to make such claim and specifically does not include interruption in fuel supply. The CEP agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with the Company's system if the same are rendered inoperable due to actions of the CEP, its agents, or Force Majeure events affecting the Facility or the interconnection with the Company.

If the Facility is interconnected to the Company's transmission system, the Company agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by the Company or its agents.

e. Representations, Warranties, and Covenants of the CEP
The CEP represents and warrants that as of the date this Contract is executed:

i. **Organization, Standing and Qualification:** The CEP is a (corporation, partnership, or other, as applicable) duly organized and validly existing in good standing under the laws of and has all necessary power and authority to carry on its business as presently conducted, to own or hold under lease its properties and to enter into and perform its obligations under this Contract and all other related documents and agreements to which it is or shall be a Party. The CEP is duly qualified or licensed to do business in the State of Florida and in all other jurisdictions wherein the nature of its business and operations or the character of the properties owned or leased by it makes such qualification or licensing necessary and where the failure to be so qualified or licensed would impair its ability to perform its obligations under this Contract or would result in a material liability to or would have a material adverse effect on the Company.

ii. **Due Authorization, No Approvals, No Defaults, etc.:** Each of the execution, delivery and performance by the CEP of this Contract has been duly authorized by all necessary action on the part of the CEP, does not require any approval, except as has been heretofore obtained, of the (shareholders, partners, or others, as applicable) of the CEP or any consent of or approval from any trustee, lessor or holder of any indebtedness or other obligation of the CEP, except for such as have been duly obtained, and does not contravene or constitute a default under any law, the (articles of incorporation, bylaws, or other as applicable) of the CEP, or any agreement,

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.252
CANCELS FIRST REVISED SHEET NO. 8.252

Continued from Sheet No. 8.248

judgment, injunction, order, decree or other instrument binding upon the CEP, or subject the Facility or any component part thereof to any lien other than as contemplated or permitted by this Contract.

iii. **Compliance with Laws**: The CEP has knowledge of all laws and business practices that must be followed in performing its obligations under this Contract. The CEP is in compliance with all laws, except to the extent that failure to comply therewith would not, in the aggregate, have a material adverse effect on the CEP or the Company. By entering into this Contract, the CEP represents and warrants that Facility is a renewable facility pursuant to Rule 25-17.210(1) and(2) F.A.C. or a QF with a design capacity of 100 kW, or less, pursuant to Rule 17.080 F.A.C. and confirms such representation and warranty with the signature of the CEP's authorized representative on this Contract.

iv. **Governmental Approvals:** Except as expressly contemplated herein, neither the execution and delivery by the CEP of this Contract, nor the consummation by the CEP of any of the transactions contemplated thereby, requires the consent or approval of, the giving of notice to, the registration with, the recording or filing of any document with, or the taking of any other action in respect of governmental authority, except in respect of permits (a) which have already been obtained and are in full force and effect or (b) are not yet required (and with respect to which the CEP has no reason to believe that the same will not be readily obtainable in the ordinary course of business upon due application therefore).

v. **No Proceedings:** There are no actions, suits, proceedings or investigations pending or, to the knowledge of the CEP, threatened against it at law or in equity before any court or tribunal of the United States or any other jurisdiction which individually or in the aggregate could result in any materially adverse effect on the CEP's business, properties, or assets or its condition, financial or otherwise, or in any impairment of its ability to perform its obligations under this Contract. The CEP has no knowledge of a violation or default with respect to any law which could result in any such materially adverse effect or impairment. CEP is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

f. **Conditions Precedent**: Notwithstanding any other provisions of this Contract including the provisions of Section 20.b, the Company shall have the right to terminate this Contract by notice to the CEP, without cause, liability or obligation, if

Continued to Sheet No. 8.254

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

one or more of the following conditions, after reasonable effort by the CEP, shall not have been or cannot be satisfied in the Company's good faith judgment, and in the time periods described below. The Company in its sole discretion may extend the CEP's time for satisfying these conditions if one or more of the events described below is pending as of such date and it is reasonable to expect that such event will be accomplished within sixty (60) days:

i. The CEP satisfies the Construction Commencement Date;

ii. If the Facility is a small Qualifying Facility, on or before the Facility In-Service Date: The CEP secures certification of the Facility as a Qualifying Facility as defined herein and as certified by the FERC.

iii. If the Facility is a small Qualifying Facility, on or before the Facility In-Service Date, and at all times throughout the remaining Term, such Facility shall maintain its status as a Qualifying Facility as defined herein and as certified by the FERC. By the end of the first quarter of each calendar year, the CEP shall furnish the Company a notarized certificate by an officer of the CEP certifying that the Facility has continuously maintained qualifying status on a calendar year basis since the commencement of the Term.

iv. Within 9 months after the effective date of this Contract: The CEP secures any and all land use and zoning approvals reasonably necessary to obtain construction financing and authorizes the commencement of construction of the Facility on a basis not substantially adverse to the Company;

v. Within 9 months after the effective date of this Contract: The CEP has secured all other environmental and construction permits and other governmental approvals reasonably necessary to obtain construction financing and to begin construction of the Facility on a basis not substantially adverse to the Company;

vi. Within 9 months after the effective date of this Contract: The CEP achieves closing of financing for construction of the Facility;

vii. On or before ________________, the CEP provides to the Company written evidence of the rights to adequate fuel supply for the Facility in a form satisfactory to the Company;

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.256
CANCELS ORIGINAL SHEET NO. 8.256

Continued from Sheet No. 8.254

viii. Within 9 months after the effective date of this Contract: The CEP provides evidence in writing in a form satisfactory to the Company indicating and substantiating the ownership of or the right to use the real property at the specific site upon which the Facility will be located; and

ix. Within 9 months after the effective date of this Contract: The CEP provides sufficient information satisfactory to the Company describing the technical capability and experience of the Facility's technology, including the environmental performance of the Facility.

g. **Assignment:** The Company and the CEP shall have the right to assign its benefits under this Contract, but the CEP shall not have the right to assign its obligations and duties without the Company's prior written consent and such consent shall not be unreasonably withheld.

h. **Disclaimer:** In executing this Contract, the Company does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with the CEP or any assignee of this Contract.

i. **Notification:** For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Contract, the Parties designate the following to be notified or to whom payment shall be sent until such time as either Party furnishes the other Party written instructions changing such designate.

For: the CEP	For: the Company
______________________	c/o Manager-Wholesale Contracts,
______________________	Wholesale Marketing and Sales
______________________	Tampa Electric Company
______________________	702 North Franklin Street (33602)
______________________	P.O. Box 111
______________________	Tampa, Florida 33601

j. **Governing Law and Jurisdiction:** This Contract shall be governed by and construed and enforced in accordance with the laws, rules, and regulations of the State of Florida and the Company's Tariff as may be modified, changed, or amended from time to time. With respect to any suit, action or proceedings relating to this Contract, each party irrevocably submits to the exclusive jurisdiction of the courts of the State of Florida and the United States District Court located in

Continued to Sheet No. 8.257

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.257

Continued from Sheet No. 8.256

Hillsborough County in Tampa, Florida; and waives any objection which it may have at any time to the laying of venue of any Proceedings brought in any such court, waives any claim that such Proceedings have been brought in an inconvenient forum and further waives the right to object, with respect to such Proceedings, that such court does not have any jurisdiction over such party. Nothing shall prevent the Beneficiary from enforcing any related judgment against the Guarantor in any other jurisdiction.

- k. **Waiver of jury trial:** Each party waives, to the fullest extent permitted by applicable law, any and all rights it may have to a trial by jury in respect of any suit, action or proceeding relating to this agreement or any credit support document. Each party (i) certifies that no representative, agent or attorney of the other party or any credit support provider has represented, expressly or otherwise, that such other party would not, in the event of such a suit, action or proceeding, seek to enforce the foregoing waiver and (ii) acknowledges that it and the other party have been induced to enter into this agreement and provide for any credit support document, as applicable, by, among other things, the mutual waivers and certifications in this section.

Continued to Sheet No. 8.258

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.258
CANCELS FIRST REVISED SHEET NO. 8.258

Continued from Sheet No. 8.257

l. **Taxation:** In the event that the Company becomes liable for additional taxes, including interest and/or penalties arising from an Internal Revenue Services determination, through audit, ruling or other authority, that the Company's payments to the CEP for capacity under Options B, C, or D are not fully deductible when paid (additional tax liability), the Company may bill the CEP monthly for the costs, including carrying charges, interest and/or penalties, associated with the fact that all or a portion of these capacity payments are not currently deductible for federal and/or state income tax purposes. The Company, at its option, may offset these costs against amounts due the CEP hereunder. These costs would be calculated so as to place the Company in the same economic position in which it would have been if the entire capacity payments had been deductible in the period in which the payments were made. If the Company decides to appeal the Internal Revenue Service's determination, the decision as to whether the appeal should be made through the administrative or judicial process or both, and all subsequent decisions pertaining to the appeal (both substantive and procedural), shall rest exclusively with the Company.

m. **Severability:** If any part of this Contract, for any reason, be declared invalid, or unenforceable by a court or public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of this Contract, which remainder shall remain in force and effect as if this Contract had been executed without the invalid or unenforceable portion.

n. **Complete Contract and Amendments:** All previous communications or agreements between the Parties, whether verbal or written, with reference to the subject matter of this Contract are hereby abrogated. No amendment or modification to this Contract shall be binding unless it shall be set forth in writing and duly executed by both Parties to this Contract.

o. **Incorporation of Rate Schedule:** The Parties agree that this Contract shall be subject to all of the provisions contained in the Company's published Rate Schedule COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

p. **Survival of Contract:** This Contract, as it may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

Continued to Sheet No. 8.262

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.262
CANCELS FIRST REVISED SHEET NO. 8.262

Continued from Sheet No. 8.258

q. **Record Retention:** The CEP agrees to retain for a period of five (5) years from the date of termination hereof all records relating to the performance of its obligations hereunder, and to cause all CEP entities to retain for the same period all such records.

r. **No Waiver:** No waiver of any of the terms and conditions of this Contract shall be effective unless in writing and signed by the Party against whom such waiver is sought to be enforced. Any waiver of the terms hereof shall be effective only in the specific instance and for the specific purpose given. The failure of a Party to insist, in any instance, on the strict performance of any of the terms and conditions hereof shall not be construed as a waiver of such Party's right in the future to insist on such strict performance.

s. **Set-off:** The Company may at any time, but shall be under no obligation to, set off any and all sums due from the CEP against sums due to the CEP hereunder.

t. **Assistance With the Company FIN 46R Compliance:** Accounting rules set forth in Financial Accounting Standards Board Interpretation No. 46 (Revised December 2003) ("FIN 46R"), as well as future amendments and interpretations of those rules, may require the Company to evaluate whether the CEP must be consolidated, as a variable interest entity (as defined in FIN 46R), in the financial statements of the Company. The CEP agrees to fully cooperate with the Company and make available to the Company all financial data and other information, as deemed necessary by the Company, to perform that evaluation on a timely basis at inception of the PPA and periodically as required by FIN 46R. If the result of a the evaluation under FIN 46R indicates that the CEP must be consolidated in the financial statements of the Company, the CEP agrees to provide financial statements, together with other required information, as determined by the Company, for inclusion in disclosures contained in the footnotes to the financial statements and in the Company's required filings with the Securities and Exchange Commission ("SEC"). The CEP shall provide this information to the Company in a timeframe consistent with the Company's earnings release and SEC filing schedules, to be determined at the Company's discretion. The CEP also agrees to fully cooperate with the Company and the Company's independent auditors in completing an assessment of the CEP's internal controls as required by the Sarbanes-Oxley Act of 2002 and in performing any audit procedures necessary for the independent auditors to issue their opinion on the consolidated financial statements of the Company. The Company will treat any information provided by the CEP in satisfying Section 22(s) as confidential information and shall only disclose such information to the extent required by accounting and SEC rules and any applicable laws.

Continued to Sheet No. 8.264

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.264

IN WITNESS WHEREOF, CEP and the Company have executed this Contract the day and year first above written.

WITNESSES:

____
Name of Capacity and Energy Provider

____________________________ **By:** ____________________________

____________________________ **Its:** ____________________________

WITNESSES: **Tampa Electric Company**

____________________________ **By:** ____________________________

____________________________ **Its:** ____________________________

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.266

**EVALUATION PROCEDURE
FOR STANDARD OFFER CONTRACTS**

Standard Offer Contracts shall be evaluated and then accepted based on meeting specific criteria. This Evaluation Procedure will insure the acceptance of Standard Offer Contracts that meet the Company's needs and are in the best interest of customers.

Each eligible Standard Offer Contract received by the Company will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2.

Energy Providers submitting Standard Offer Contracts to the Company should, at the same time, submit specific information for each of the following evaluation criteria. Failure to provide this information may result in a determination of non-viability by the Company. Each eligible Standard Offer Contract received will be evaluated based upon the information provided in response to the following list of parameters:

EVALUATION PARAMETERS:

1. **Technical Viability:**
   a. What is the technology being proposed?
   b. Has the technology been demonstrated or commercially applied? Please explain.
   c. Has the CEP previously utilized this technology elsewhere?
      Construction: Please provide performance record and experience with project technology.
      Operations: Please provide operator's experience and performance record in comparable facilities.
   d. Has a project feasibility study been conducted by an Independent Engineer to assess the project technology and its potential effect on the project's financial results? Please explain.
   e. What thermal efficiency must be maintained by the unit(s) in order to retain status as a qualifying facility ("QF")?

2. **Fuel Supply:**
   a. What is the primary fuel type?
   b. What are the annual fuel requirements? (primary/alternate)
   c. Has primary fuel supply been secured? Is the fuel supply domestic, cross-border or foreign? What the term of the fuel supply agreement?
   d. Is an alternate fuel required?

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.268

e. Has an alternate fuel supply been secured? Is the alternate fuel supply domestic, cross-border or foreign? What is the term of the alternate fuel supply agreement?
f. Have transportation arrangements for both primary and alternate fuels been secured (firm/interruptible, provide detail)?
g. Are the pricing terms of the fuel supply agreement(s) directly tied to the corresponding energy payments?
h. If the fuel is considered to be renewable, please describe the renewable nature of the fuel and the environmental impact of its production and use to generate power.

3. **Reliability:**

a. Dispatchability: Will the Facility be dispatched on request or will it be base-loaded? Please explain.
b. QF Status: Has the project obtained FERC certification as a QF? Has application been made for FERC certification? Please explain.
c. Operations and Maintenance: Who will provide O&M for the Facility: (a) developer; or (b) third party? If third party, please provide the name and address of the third party that will be used and any information that would describe their capability to perform this role.
d. Thermal Energy Host: If project is QF, provide the following information regarding any thermal energy (e.g. steam) host associated with the project:
   i. Please explain the importance of the energy, taken by the thermal energy host, to the overall operations of the thermal energy host.
   ii. Are there adequate alternative candidates in close proximity to the Facility that could serve as a potential thermal energy host replacement?
   iii. What is the minimum thermal energy "take" necessary for the project to maintain QF status?
   iv. Has a thermal energy host been secured?
   v. Is the thermal energy host already in existence?
   vi. Is it a new thermal energy host? (Is it identifiable?)
   vii. What are the thermal energy host's operating hours?
   viii. Are the thermal energy host's business cycle or thermal requirements seasonal? If so explain.
e. Permits: What permits or licenses will be required for the project? Have the necessary permits or licenses been secured? What specific environmental considerations must the project meet?
f. Construction Schedule: Has a construction schedule including milestones been formulated? Please provide detail.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.278
CANCELS ORIGINAL SHEET NO. 8.278

Continued from Sheet No. 8.268

g. Site Control: Has the project's location been identified? Has the site been secured? Does the site require specific environmental considerations, i.e. wetlands, etc.? Please explain.

4. **Developer's Qualifications:**

a. Project's Financial Stability: The Company will assess the creditworthiness of the project developer and/or its guarantor, if any, and determine in the Company's reasonable sole discretion if the project developer's level of unsecured credit is sufficient to provide the required Security to the Company. Please provide detail for the project developer or its guarantor, if any: (a) audited year-end financial statements (including balance sheet, income statement, and statement of cash flows) for the past three fiscal years, and (b) senior unsecured bond ratings from Moody's Investors Service and Standard and Poor's, if applicable.

b. Developer's Experience: Has developer any projects in operation? Has developer any other projects under construction? Please provide details for each previous Independent Power Production or QF projects undertaken by the developer, including but not limited to:

   i. Financial arrangements and Institutions,
   ii. Fuel contracts,
   iii. Scheduling/project control information,
   iv. Regulatory treatment,
   v. Ownership structure, i.e. partnership, limited partnership, contract buy-outs, etc., and
   vi. Total operating experience and performance.

c. Project Financing: Has project financing been secured? Will ownership equity in project be 15% or greater? Will the project be structured as a non-recourse financing project? Please provide detail.

d. Working Capital: Has long-term working capital been secured? Are sufficient reserves available to fund 6 months of debt service? Are sufficient funds available to cover 6 months of O&M expenses? Does project have warranties for key operating equipment during the first year of operations? Please provide detail.

5. **Additional Information:** Please provide the following additional general information to assist the Company in evaluating your Standard Offer Contract

a. Standard Offer Committed Capacity (MW):

b. Size and type of generation:

c. Any existing or planned capacity commitments or energy sales to other utilities, if so provide detail:

Continued to Sheet No. 8.282

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.282
CANCELS ORIGINAL SHEET NO. 8.282

Continued from Sheet No. 8.278

d. Will the project directly interconnect into the Company's transmission grid? Please explain:

e. If the project is located external to the Company's retail service area, how will the power be delivered to the Company? Please explain:

f. Will steam host use a portion of electric generation, if so provide detail:

g. Please provide developer's ownership structure for this project:

h. Developer's insurance carrier:

- Property damage insurance:
- Business interruption insurance:
- Rating of insurance carrier:

i. Please provide estimates of the following:

- Expected annual metered electric output,
- Expected annual metered useful thermal output, in Btu/hr X operating hours/year,
- Expected annual metered fuel input, in Btu/hr X operating hours/year

j. Other:

EVALUATION CRITERIA AND SCORING: The Company will accept a Standard Offer Contract on the basis of the information provided in response to the evaluation criteria and upon its judgment of other relevant factors. A Standard Offer Contract which has convincingly demonstrated that the project is financially and technically viable and that the committed capacity would be available by the date specified in the Standard Offer Contract will be accepted for further negotiations leading to a contract offer.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.284

STANDARD OFFER CONTRACT RATE FOR
PURCHASE OF CONTRACTED CAPACITY AND ASSOCIATED ENERGY

SCHEDULE: COG-2, firm capacity and energy

AVAILABLE: Tampa Electric Company, herein after referred to as the "Company," will purchase firm capacity and energy offered by renewable generating facilities or qualifying facilities with a design capacity of 100 kW or less ("small qualifying facility") to which a Standard Offer Contract is available under Chapter 366.91 Florida Statutes (F.S) and Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.300, Florida Administrative Code (F.A.C.). Unless specifically referred to, a renewable generation facility or a small qualifying facility may be referred to as the "Capacity and Energy Provider" or "CEP". The Company has designated the generating units identified in Appendices C through F, as its Designated Avoided Units. Pursuant to FPSC Rule 25-17.250(2), the Company will accept firm capacity and energy offered by any CEP under the provisions of this schedule for a specific Designated Avoided Unit until:

1. A request for proposals (RFP) pursuant to Rule 25-22.082, F.A.C., is issued for the specific planned generating unit; or
2. The utility files a petition for a need determination or commences construction for the specific generating unit not subject to Rule 25-22.082, F.A.C., or
3. The generating unit upon which the standard offer contract was based is no longer part of the utility's generation plan, as evidenced by FPSC approval of a petition to that effect filed with the FPSC or by its removal from the utility's most recent Ten Year Site Plan.

The Company will negotiate and may contract with any CEP as defined to in Chapter 366.91 F. S. and FPSC Rule 25-17.080, F.A.C., irrespective of its location, which is either directly or indirectly interconnected with the Company, for the purchase of firm capacity and energy pursuant to terms and conditions which deviate from this schedule where such negotiated contracts are in the best interest of the Company's ratepayers and subject to FPSC approval of such a contract.

APPLICABLE: To any CEP to which Standard Offer Contracts are available under Chapter 366.91 F. S. and FPSC Rule 25-17.0832(4)(a), F.A.C., irrespective of its location, producing capacity and energy for sale to the Company on a firm basis pursuant to the terms and conditions of this schedule and the Company's Standard Offer Contract or a separately negotiated contract.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.286

Firm capacity and energy are described in FPSC Rule 25-17.0832, F.A.C., and are capacity and energy produced and sold by the CEP pursuant to a negotiated or Standard Offer Contract and subject to certain contractual provisions as to quantity, time and reliability of delivery. Criteria for achieving CEP status shall be those set out in Chapter 366.91 F.S. and FPSC Rules 25-17.080, 25-17.082(4)(a), and 25-17.091, F.A.C., as applicable.

CHARACTER OF SERVICE: Purchases within the territory served by the Company shall be, at the option of the Company, single or 3-phase, 60 Hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three-phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering firm capacity and energy from the CEP.

LIMITATIONS: Purchases under this schedule are subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System (if applicable)," Federal Energy Regulatory Commission (FERC) Electric Open Access Transmission Tariff (OATT) and associated transmission interconnection tariffs (if applicable), North American Electric Reliability Council (NERC) and Florida Reliability Coordinating Council (FRCC) Reliability Standards, that are applicable to generation and transmission facilities which are connected to, or being planned to be connected to the Company's transmission system (document provided upon request) and to FPSC Rules 25-17.080 through 25-17.091, F.A.C. and are limited to those CEPs which are defined by FPSC Rule 25-17.082(4)(a), F.A.C. and which:

1. execute a Company Standard Offer Contract for the Company's purchase of firm capacity and energy; and

2. commit to commence deliveries of firm capacity and energy no later than the in-service date of the Designated Avoided Unit, and to continue such deliveries through the later of the last day of the tenth year following the in-service date of the avoided unit or the date selected by the CEP that is no later than the day after the last day of the life of the avoided unit.

RATES FOR PURCHASES BY THE COMPANY: firm capacity and energy are purchased at unit costs, in dollars per kilowatt per month ($/kW/month) and cents per kilowatt-hour (¢/kWh), respectively, based on the value of deferring additional Company generating capacity.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

Firm capacity and energy are described in FPSC Rule 25-17.0832, F.A.C., and are capacity and energy produced and sold by the CEP pursuant to a negotiated or Standard Offer Contract and subject to certain contractual provisions as to quantity, time and reliability of delivery. Criteria for achieving small qualifying facility or renewable facility status shall be those set out in Chapter 366.91 F.S. and FPSC Rules 25-17.080, 25-17.082(4)(a), and 25-17.091, F.A.C., as applicable.

1. **Firm Capacity Rates:** Five options (i.e. Options 1, 2, 3, 4, and 5, as set forth below) are available for payment of firm capacity which is produced by the CEP and delivered to the Company. Once selected, the selected option shall remain in effect for the term of the contract with the Company. Exemplary payment schedules for Options 1 through 4, shown for each Designated Avoided Unit are identified in Appendices C through F, contain the monthly rate per kilowatt (kW) of firm capacity the CEP could contractually commit to deliver to the Company. These examples are based on a contract term which extends at least ten years beyond the in-service date of the Designated Avoided Unit. Payment schedules for longer contract terms will be made available to the CEP upon request and may be calculated based on the methodologies described in Appendix A. A payment schedule for Option 5, if selected by the CEP, will be calculated based on Appendix A and the Option 5 description contained in Section 6.b.iii.(5) of the Standard Offer Contract and will be made available by the Company within 30 days of a request by the CEP. At a maximum, firm capacity and energy shall be delivered for a period of time equal to the anticipated plant life of the Designated Avoided Unit, commencing with the in-service date of the Designated Avoided Unit.

   Option 1 - Value of Deferral Capacity Payments:
   Value of Deferral Capacity Payments shall commence the in-service date of the Designated Avoided Unit, provided the CEP is delivering firm capacity and energy to the Company in accordance with the Minimum Performance Standards (MPS) as described for each Designated Avoided Unit contained in Appendices C through F. Capacity payments under this option shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit and shall be equal to the value of the year-by-year deferral of the Designated Avoided Unit, calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A.

   Option 2 - Early Capacity Payments:
   Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit. The earliest date that Early Capacity Payments can be received by the CEP shall be the Commercial In-service Date of the CEP's generating facility. The CEP shall select the

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.292

month and year in which the delivery of firm capacity and energy to the Company is to commence and capacity payments are to start. Early Capacity Payments shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit. Avoided Capacity Payments shall be calculated in conformance with FPSC Rules 25-17.0832 and 25-17.250(4), F.A.C., as described in Appendix A. At the option of the CEP, Early Capacity Payments may commence at any time after the specified earliest capacity payment date and before the in-service date of the Designated Avoided Unit provided the CEP is delivering firm capacity and energy to the Company in accordance with MPS as described for each Designated Avoided Unit contained in Appendices C through F. Where Early Capacity Payments are elected, the cumulative present value of the capacity paid to the CEP over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the CEP had such payments been made pursuant to Option 1.

Option 3 - Levelized Capacity Payments:
Levelized capacity payments shall commence on the in-service date of the Designated Avoided Unit, provided the CEP is delivering firm capacity and energy to the Company in accordance with the MPS as described for each Designated Avoided Unit contained in Appendices C through F. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payment shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. Where Levelized Capacity Payments are elected, the cumulative present value of the capacity paid to the CEP over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the CEP had such payments been made pursuant to Option 1.

Option 4 - Early Levelized Capacity Payments:
Early Levelized Capacity Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit. The earliest date that Early Levelized Capacity Payments can be received by the CEP shall be the Commercial In-service Date of the CEP's generating facility. The capital portion of the capacity payment under this Option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payments shall be equal to

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. At the option of the CEP, Early Levelized Capacity Payments shall commence at any time beginning on or after the Commercial In-service Date of the CEP's generating facility and before the in-service date of the Designated Avoided Unit provided the CEP is delivering firm capacity and energy to the Company in accordance with the MPS as described for each Designated Avoided Unit contained in Appendices C through F. The CEP shall select the month and year in which the delivery of firm capacity and energy to the Company is to commence and capacity payments are to start. Where Early Levelized Capacity Payments are elected, the cumulative present value of the capacity payments paid to the CEP over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the CEP had such payments been made pursuant to Option 1.

Option 5 - Other
In accordance with FPSC Rule 25-17.250(4) F.A.C., the CEP may elect a payment stream for the capital component of the Company's avoided unit, including front-end loaded payments, that best meets the financing requirements of the CEP. Where front-end loaded capacity payments are elected, the cumulative present value of the capacity payments paid to the CEP over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the CEP had such payments been made pursuant to Option 1. A payment schedule for Option 5 will be developed reflecting the interests of the CEP for front-end loading and will be made available for review by the CEP within 30 days of the date of the request for Option 5, and interests of the CEP have been made known to the Company. Any such Option 5 selection may require additional associated security considerations that will be developed by the Company and presented to the CEP at the same time as the payment schedule. The payment schedule and security considerations will be subject to mutual agreement and approval by the FPSC.

The Company will provide the CEP with a schedule of capacity payment rates based on the month and year in which the delivery of firm capacity and energy are to commence and the term of the contract. The currently approved parameters used to calculate the schedule of payments for each Designated Avoided Unit are found in Appendices D through G of this Schedule.

Regardless of the payment stream elected by the CEP, the cumulative present value of capital cost payments made to the CEP over the term of this Agreement shall not exceed the cumulative present value of the capital cost payments which would have been made to the CEP had such payments been made pursuant to FPSC Rule 25-17.0832(4)(g)1., F.A.C. All fixed operation and maintenance expense shall be calculated in conformance with FPSC Rule 25-17.0832(6), F.A.C.

2. **Standard Energy Payment Rates:**

The calculation of energy payments to the CEP shall be based on the sum, over all hours of the Monthly Period, of the product of each hour's Energy Payment Rate times the energy purchased from the CEP by the Company for that hour. All purchases shall be adjusted for losses reflecting delivery voltage.

a. **As-available Energy Payment Rate:** "As-Available Energy" is energy generated by the CEP's facility for purchase by the Company during time periods when the Designated Avoided Unit would not have been operated had it been installed by the Company. The payment rate in ¢/kWh for As-Available Energy is based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Avoided energy costs include incremental fuel and identifiable variable operation and maintenance expenses.

   The methodology to be used in the calculation of the avoided energy costs is described in Appendix B.

   The As-available Energy Payment rate will apply to energy delivered by the CEP in the period prior to the in-service date of the Designated Avoided Unit and the periods after the in-service date of the Designated Avoided Unit to the extent that the Designated Avoided Unit would have been dispatched and operated by the Company.

b. **Unit Energy Payment Rate**: To the extent that the Designated Avoided Unit would have been dispatched and operated by the Company, the Unit Energy Payment Rate in ¢/kWh will apply and shall be based on the cost of fuel used by and variable operating and maintenance expense associated with the Designated Avoided Unit The calculation used to determine the Unit Energy Payment Rate is shown under part 2 of the section titled "Basis for Monthly Energy Payment Calculation" of the Designated Avoided Unit Appendices, "C" through "F".

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.298
CANCELS ORIGINAL SHEET NO. 8.298

3. **Fixed Energy Payment Options:**
   a. **Fixed As-Available Energy Payments:** In accordance with FPSC Rule 25-17.250(6)(a) F.A.C., the CEP may elect Fixed As-Available Energy Payments for the period prior to the in-service date of the avoided unit. The Fixed As-Available Energy Payments shall be based on the Company's year-by-year projection of system incremental fuel costs prior to hourly economy energy sales to other utilities, based on normal weather and fuel market conditions plus a fuel market volatility risk premium mutually agreed upon by the Company and the CEP and approved by the FPSC.

   b. **Fixed Base Energy Payments:** At the election of the CEP, a portion of the base energy costs associated with the avoided unit, mutually agreed upon by the Company and the CEP, may be fixed and amortized on a present value basis over the term of the contract starting as early as the in-service date of the CEP's generating facility pursuant to FPSC Rule 25-17.250(6)(b) F.A.C. "Base energy costs associated with the avoided unit" means the energy costs of the avoided unit to the extent the unit would have been operated. The Company shall develop a schedule of such Fixed Base Energy Payments for the consideration of the CEP based on the expressed interests of the CEP. Should the CEP select Fixed Base Energy Payments, the Company may require additional associated security considerations which will also be mutually agreed upon by the Company and the CEP and approved by the FPSC.

PERFORMANCE CRITERIA: In addition to the following provisions, payments for firm capacity are conditioned on the CEP's ability to meet or exceed the Minimum Performance Standards (MPS) for each of the Company's Designated Avoided Unit as described for each in Appendices C through F:

1. **CEP's Commercial In-Service Date:** Capacity Payments shall not commence until the CEP has attained and demonstrated commercial in-service status. The Commercial In-Service Date of the CEP shall be defined as the first day of the month following the successful completion by the CEP of maintaining an hourly kW output for a 24 hour period, as metered at the point of interconnection with the Company, equal to or greater than the CEP's "Contracted Capacity" as designated in the Standard Offer Contract. A CEP shall coordinate the operation of its facility during this test period with the Company to insure that the performance of its facility during this 24 hour period is reflective of the anticipated day to day operation of the CEP.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.302

2. **Monthly Availability and Monthly Capacity Factor:** Upon achieving commercial in-service status, payments for firm capacity shall be made monthly in accordance with the capacity payment rate option selected by the CEP and subject to the provision that the CEP equals or exceeds the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit, as defined in Appendices C through F of this schedule, on which the Standard Offer Contract is based.

3. **CEP's Obligation if CEP Receives Capacity Payments Under Capacity Payments Options 2, 3, 4, or 5:** The CEP's payment option choice pursuant to Paragraph 6.b.iii of the Company's Standard Offer Contract may result in payments made by the Company for capacity delivered prior to the in-service date of the avoided unit. Similarly, Levelized and Early-Levelized, and front-end loaded Other Capacity Payments for capacity delivered on or after the in-service date of the avoided unit, may also exceed the year-by-year value of deferring the Designated Avoided Unit as specified in this Agreement. The Parties recognize that capacity payments that exceed the year-by-year value of deferring the avoided unit may have to be repaid by the CEP in the event the CEP fails to perform pursuant to the terms and conditions of the Company's Standard Offer Contract.

   To ensure that the CEP will satisfy its obligation to make any repayment to the Company, the following provisions will apply:

   The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the CEP to the Company. Amounts shall be added to the Repayment Account each month through the month prior to the in-service month of the avoided unit, in the amount of the Company's Early Capacity Payments made to the CEP pursuant to the CEP's chosen payment option.

   Beginning on the in-service date of the avoided unit, the difference between the capacity payment made to the CEP and the "normal" capacity payment calculated pursuant to Option 1 will also be added each month to the Repayment Account, so long as the payment to the CEP is greater than the monthly payment the CEP would have received if it had selected Option 1 in Paragraph 6.b.iii, of the Company's Standard Offer Contract.

   Also beginning on the in-service date of the avoided unit, at such time that the Monthly Capacity Payment made to the EP, pursuant to the Capacity Payment Option selected, is less than the "normal" Monthly Capacity Payment in Option 1, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TEC⊖
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.304

the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if capacity payments had been calculated pursuant to Option 1 and the CEP had elected to begin receiving capacity payments on the in-service date of the avoided unit minus the Monthly Capacity Payment the Company makes to the CEP (assuming the MPS are met or exceeded), pursuant to the Capacity Payment Option chosen by the CEP.

Monthly Capacity Payments will not be made to the CEP for any month the CEP fails to meet the MPS and if applicable, a payment will be required by the CEP to the Company in an amount equal to the Early Payment Offset for that month. In the event a payment is required from the CEP to the Company, the CEP's Repayment Account will be reduced by the amount of such payment provided that any such payment will not exceed the current balance in the Repayment Account.

The CEP shall owe the Company and be liable for the current balance in the Repayment Account. The annual balance in the Repayment Account shall accrue interest at an annual rate of 7.88%. The Company agrees to notify the CEP monthly as to the current Repayment Account balance.

In the event of default by the EP, the total Repayment Account balance shall become due and payable within 20 business days of receipt of written notice, as reimbursement for the Capacity Payments made to the CEP by the Company in excess of "normal capacity payments.

The CEP's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the CEP's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the CEP.

Prior to receipt of Early, Levelized, Early-Levelized, or front-end loaded Other Capacity Payments the CEP shall secure its obligation to repay any balance in the Repayment Account in the event the CEP defaults under the terms of its Standard Offer Contract with the Company.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

SEVENTH REVISED SHEET NO. 8.306
CANCELS SIXTH REVISED SHEET NO. 8.306

Continued from Sheet No. 8.304

Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the EP; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the CEP.

Florida Statute 377.709(4) requires a local government to refund Early Capacity Payments should a Municipal Solid Waste Facility owned, operated by or on the behalf of the local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832 (2)(c) and (3)(e)(8), F. A. C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

4. **Additional Criteria:**

   a. The CEP shall provide monthly generation estimates by December 1 for the next calendar year; and

   b. The CEP shall promptly update its yearly generation schedule when any changes are determined necessary; and

   c. The CEP shall agree to reduce generation or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and

   d. The CEP shall coordinate scheduled outages with the Company;

   e. The CEP shall comply with the reasonable requests of the Company regarding daily or hourly communications.

DELIVERY VOLTAGE ADJUSTMENT: Energy Payments to CEPs within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0534
GSD, SBF	1.0496
IS, SBI	1.0185

Continued to Sheet No. 8.308

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: December 31, 2015

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.308

METERING REQUIREMENTS: CEPs within the territory served by the Company shall be required to purchase from the Company the necessary hourly recording meters to measure their energy production. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period. Energy purchases from CEPs outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering firm capacity and energy to the Company.

BILLING OPTIONS: The CEP, upon entering into a contract for the sale of Contracted Capacity and Associated Energy or prior to delivery of As-Available Energy to the Company, shall elect to make either simultaneous purchases from the interconnecting utility and sales to the Company or net sales to the Company. The billing option elected may only be changed:

1. when the CEP selling As-Available Energy enters into a negotiated contract or Standard Offer Contract for the sale of firm capacity and energy; or
2. when a firm capacity and energy contract expires or is lawfully terminated by either the EP, or the Company; or
3. when the CEP is selling As-Available Energy and has not changed billing methods within the last 12 months; and
4. when the election to change billing methods will not contravene the provisions of FPSC Rule 25-17.0832, F.A.C., or any contract between the CEP and the Company.

If the CEP elects to change billing methods in accordance with FPSC Rule 25-17.082, F.A.C., such a change shall be subject to the following provisions

1. upon at least 30 days advance written notice to the Company; and
2. upon the installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology and upon payment by the CEP for such metering equipment and its installation; and
3. upon completion and approval by the Company of any alterations to the interconnection reasonably required to effect the change in billing methodology and upon payment by the CEP for such alterations

Should the CEP elect the Simultaneous Purchases and Sales billing option, purchases of electric service by the CEP from the interconnecting utility shall be billed at the retail rate schedule under which the CEP load would receive service as a customer of the utility; sales of electricity delivered by the CEP to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.312
CANCELS FIRST REVISED SHEET NO. 8.312

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.00		
GS	18.00	GST	20.00
GSD (secondary)	30.00	GSDT (secondary)	30.00
GSD (primary)	130.00	GSDT (primary)	130.00
GSD (subtrans.)	990.00	GSDT (subtrans.)	990.00
SBF (secondary)	55.00	SBFT (secondary)	55.00
SBF (primary)	155.00	SBFT (primary)	155.00
SBF (subtrans.)	1,015.00	SBFT (subtrans.)	1,015.00
IS (primary)	622.00	IST (primary)	622.00
IS (subtrans.)	2,372.00	IST (subtrans.)	2,372.00
SBI (primary)	647.00		
SBI (subtrans.)	2,397.00		

Continued to Sheet No. 8.314

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: November 1, 2013

If CEP takes service under Rate Rider GSLM-2 or GSLM-3, an additional Basic Service Charge of $200.00 will apply.

When appropriate, the Basic Service Charge will be deducted from the CEP's monthly payment. A statement of the charges or payments due the CEP will be rendered monthly. Payment normally will be made by the 20th business day following the end of the billing period.

2. **Interconnection Charge for Non-Variable Utility Expenses:** The CEP shall bear the cost required for interconnection including the metering. The CEP shall have the option of payment in full for interconnection or make equal monthly installment payments over a 36 month period together with interest at the rate then prevailing for 30 days highest grade commercial paper; such rate to be determined by the Company 30 days prior to the date of each payment.

3. **Interconnection Charge for Variable Utility Expenses:** The CEP shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These costs include a) the Company's inspections of the interconnection and b) maintenance of any equipment beyond that which would be required to provide normal electric service to the CEP with respect to other Customers with similar load characteristics.

4. **Taxes and Assessments:** The CEP shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of firm capacity and energy produced by the CEP.

   If the Company obtains any tax savings as a result of its purchases of firm capacity and energy produced by the CEP, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the CEP.

5. **Emission Allowance Clause:** Subject to approval by the FPSC, the CEP shall receive a monthly credit, to the extent the Company can identify the same, equal to the value, if any, of any reduction in the number of air emission allowances used by the Company as a result of its purchase of firm capacity and energy produced by the EP; provided that no such credit shall be given if the cost of compliance associated with air emission standards is included in the determination of full avoided cost.

TERMS OF SERVICE:

1. It shall be the CEP's responsibility to inform the Company of any change in its electric generation capability.

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.316

2. Any electric service delivered by the Company to the CEP shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3. A billing security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:

   a. In the first year of operation, the security deposit should be based upon the singular month in which the CEP's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the CEP. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit should be required upon interconnection.

   b. For each year thereafter, a review of the actual sales and purchases between the CEP and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the CEP exceed the actual sales to the utility in that month.

4. The Company will, under the provisions of this Schedule, require an agreement with the CEP upon the Company's filed Standard Offer Contract.

5. Service under this rate schedule is subject to the rules and regulations of the Company and the FPSC.

SPECIAL PROVISIONS:

1. Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the FPSC

2. In accordance with the provision in FPSC Rule 25-17.0883, F.A.C., the Company is required to provide transmission and distribution service to enable a retail customer, at that customer's request, to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale Customers or adversely affect the adequacy or reliability of electric service to all Customers.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.318

A determination of whether or not such service is likely to result in higher cost electric service will be made by the Company by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3. In accordance with FPSC Rule 25-17.089, F.A.C., upon request by a CEP, the Company shall provide transmission service in accordance with its OATT to wheel As-Available Energy or firm capacity and energy produced by the CEP from the CEP to another electric utility.

4. The rates, terms, and conditions for any transmission and ancillary services provide to the CEP shall be those approved by the FERC and contained in the Company's OATT.

5. A CEP may apply for transmission and ancillary services from the Company in accordance with the Company's OATT. Requests for service must be submitted on the Company's Open Access Same-Time Information System ("OASIS"). The Company's contact person, phone number and address is posted and updated on the OASIS and can be viewed by the public on the Internet at the address: http://www.enx.com/FOA_Contacts.html. A copy of the Company's OATT is also posted at the address: http://www.enx.com/FOA/teco home.html.

6. If the CEP is located outside of the Company's transmission area, then the CEP must arrange for long term firm 3rd-party transmission, ancillary services and an Interconnection Agreement on all necessary external transmission paths for the term of the contract.

PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS: Within 60 days of the receipt of a signed, completed Standard Offer Contract, the Company shall either accept and sign the Standard Offer Contract and return it within 5 days to the CEP or petition the Commission not to accept the Standard Offer Contract and provide justification for the refusal.

All Standard Offer Contracts received will be given equal consideration and each will be reviewed in accordance with the Company's Evaluation Procedure for Standard Offer Contracts. The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix I.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.322

Each delivered Standard Offer Contract should be clearly labeled "Standard Offer Contract" and shall only be received at the Company's main business address:

Tampa Electric Company
c/o Manager - Wholesale Contracts,
Wholesale Marketing and Sales
702 North Franklin Street (33602)
P. O. Box 111
Tampa, Florida 33601

Certified mail will be the preferred means of Standard Offer Contract delivery.

Each eligible Standard Offer Contract will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C.

The Company will select and accept Standard Offer Contracts, after the evaluation process, which have convincingly demonstrated that their project is financially and technically viable and that the Contracted Capacity and Associated Energy would be available by the date specified in the Standard Offer Contract.

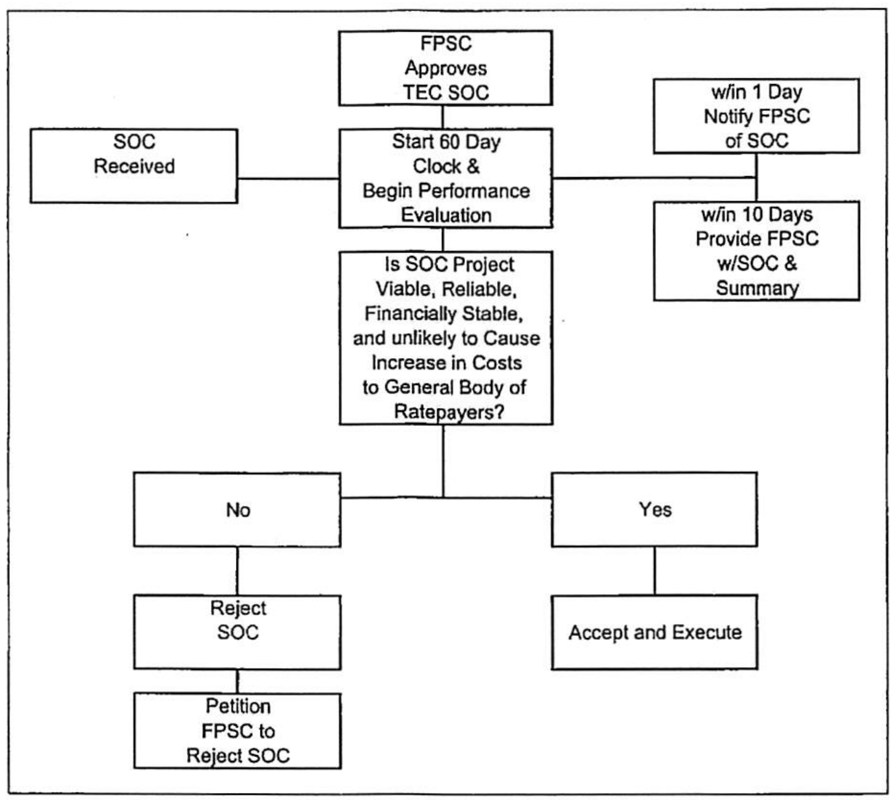
ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.324

PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS



ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

~~SIXTH~~ SEVENTH REVISED SHEET NO. 8.326
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 8.326

RATE SCHEDULE COG-2
TABLE OF APPENDICES

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.328

RATE SCHEDULE COG-2
APPENDIX A
VALUE OF DEFERRAL METHODOLOGY

Appendix A provides a detailed description of the methodology used by the Company to calculate the monthly value of deferring the Designated Avoided Unit referred to in Rate Schedule COG-2. When used in conjunction with the current FPSC-approved cost parameters associated with each Designated Avoided Unit contained in Appendices C through E, the CEP may determine the applicable value of deferral capacity payment rate associated with the timing and operation of its particular facility should the CEP enter into a Standard Offer Contract with the Company.

Also contained in Appendix A is a discussion of the types and forms of surety bond requirements or equivalent assurance of repayment of early, Levelized, Early Levelized, or front-end loaded Other Capacity Payments acceptable to the Company in the event of contractual default by the CEP.

CALCULATION OF VALUE OF DEFERRAL: FPSC Rule 25-17.0832(6), F.A.C., specifies that avoided capacity costs, in dollars per kilowatt per month, associated with firm capacity sold to a utility by the CEP pursuant to the utility's Standard Offer shall be defined as the value of a year-by-year deferral of the Designated Avoided Unit and shall be calculated as follows:

$$VAC_m = 1/12\ [KI_n\ (1-R_p)\ /\ (1-R_p\ ^L) + O_n]$$

FPSC Rule 25-17.0832(6)(a), F.A.C., specifies that, beginning with the in-service date of the Company's Designated Avoided Unit, for a one year deferral:

VAC_m = Company's monthly value of avoided capacity, $/kW/month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.332

I_n = total direct and indirect cost, in mid-year $/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit(s) been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year $/kW/year, of the Designated Avoided Unit(s);

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

r = annual discount rate, defined as the Company's incremental after tax cost of capital;

L = expected life of the Designated Avoided Unit(s); and

R_P = $(1 + i_p) / (1 + r)$

n = year for which the Designated Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.

CALCULATION OF EARLY CAPACITY PAYMENTS: FPSC Rule 25-17.0832(6)(b), F.A.C., specifies that, normally, payment for firm capacity shall not commence until the in-service date of the Designated Avoided Unit(s). At the option of the CEP, however, the Company may begin making Early Capacity Payments consisting of the fixed operation and maintenance expense and the capital cost component of the value of a year-by-year deferral of the Designated Avoided Unit(s). When such Early Capacity Payments are elected, capacity payments shall be paid monthly commencing no earlier than the Commercial In-Service date of the CEP, and shall be calculated as follows:

$$A_m = [A_c(1 + i_p)^{(m-1)} + A_o(1 + i_o)^{(m-1)}]/12 \qquad \text{for } m = 1 \text{ to } t$$

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DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.334

Beginning with the earliest avoidance date of the Company's Designated Avoided Unit(s), for a one year deferral:

A_m = monthly early capacity payments to be made to the CEP for each month of the contract year n, in \$/kW/month, starting no earlier than the in-service date of the CEP's generating facility;

m = year for which early capacity payments to the CEP are made;

t = the term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;

$$A_c = F\ [(1 - R_p) / (1 - R_p{}^t)]$$

Where:

F = the cumulative present value, in the year contractual payments will begin, of the avoided capital cost component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s);

$$A_o = G\ [(1 - R_o) / (1 - R_o{}^t)]$$

Where:

G = the cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s).

R_o = $(1 + i_o) / (1 + r)$

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TECO TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.336
CANCELS ORIGINAL SHEET NO. 8.336

Continued from Sheet No. 8.334

CALCULATION OF LEVELIZED AND EARLY LEVELIZED CAPACITY PAYMENTS: FPSC Rule 25-17.0832(6)(c), F.A.C., specifies that, Monthly Levelized and Early Levelized Capacity Payments shall be calculated as follows:

$$P_L = F/12 \{r / [1 - (1 + r)^{-t}]\} + O$$

Where:

P_L = the monthly levelized capacity payment, starting on or prior to the in-service date of the Designated Avoided Unit(s);

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with FPSC Rule 25-17.0832, paragraph 6(a) for Levelized Capacity Payments or with paragraph 6(b) for Early Levelized Capacity Payments, F.A.C.

Currently approved parameters for each Designated Avoided Unit applicable to the formulas above are found in Appendices C through F.

CALCULATION OF MONTHLY AVAILABILITY AND CAPACITY FACTOR: Pursuant to FPSC Rule 25-17.0832, F.A.C., and Docket No. 891049-EU, the CEP must meet or exceed, on a monthly basis, the MPS of the Company's Designated Avoided Unit(s) as described in Appendices C through F of COG-2 in order to receive monthly capacity payments. At the end of each Monthly Period, beginning with the Monthly Period specified in Paragraph 6.b.ii of the Company's Standard Offer Contract, the Company will calculate the CEP's Monthly Availability and Monthly Capacity Factor.

REPAYMENT OF EARLY CAPACITY PAYMENTS: FPSC Rule 25-17.0832(3)(c), F.A.C., requires that when early, levelized, early levelized, and front-end loaded capacity payments are elected, the CEP must provide a security deposit for assurance of repayment of Early Capacity Payments in the event the CEP is unable to meet the terms and conditions of its contract. Depending on the nature of the CEP's operation, financial health and solvency of the CEP or its guarantor, if any, and its ability to meet the terms and conditions of the Company's Standard Offer Contract; one of the following may constitute an equivalent assurance of repayment:

Continued to Sheet No. 8.338

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: June 30, 2009

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.338

1. cash deposited in an interest bearing escrow account mutually acceptable to the Company and the EP; or
2. an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or
3. a performance bond in form and substance satisfactory to the Company.

The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the CEP fails to meet the terms and conditions of its contract

The Company will cooperate with each CEP applying for Capacity Payments under Capacity Payment Options 2, 3, 4, or 5 to determine the exact form of an "equivalent assurance of repayment" to be required based on the particular aspects of the CEP. The Company will endeavor to accommodate an equivalent assurance of repayment which is in the best interests of both the CEP and the Company's ratepayers.

Florida Statute 377.709(4), requires the local government to refund Early Capacity Payments should a Municipal Solid Waste Facility owned, operated by or on behalf of a local government be abandoned, closed down or rendered illegal, therefore a utility may not require risk-related guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.344
CANCELS FIRST REVISED SHEET NO. 8.344

RATE SCHEDULE COG-2
APPENDIX B
METHODOLOGY TO BE USED IN THE CALCULATION OF AVOIDED ENERGY COST

The methodology the Company has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to CEPs is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990; the Amendment of FPSC Rules 25-17.080 et seq, F.A.C.

The avoided energy costs methodology used to determine payments to CEPs on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchased power costs and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the CEP's contribution. When this is the case and the CEP is present, the incremental fuel portion of the avoided energy cost is equal to the difference between the Company's production cost at 2 load levels, with and without the CEP's contribution.

In those situations where the Company's maximum available generation (not including its minimum operating reserves) is insufficient to carry its native load and firm interchange sales, in the absence of the CEP contribution, the Company's incremental fuel component of the avoided energy cost will be determined by:

1. system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2. the highest incremental cost of any "off-system purchases" that are being made for native load.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.352
CANCELS ORIGINAL SHEET NO. 8.352

Examples of these situations are found in Exhibits 1- 4.

The As-Available Avoided Energy Cost, as determined by this methodology, is priced at a level not to exceed the Company's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

PARAMETERS FOR DETERMINING AS-AVAILABLE AVOIDED ENERGY COSTS: The Company uses production costing methods for determining avoided energy cost payments to CEPs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of the Company's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (paragraph 4 above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour.

8. Firm interchange sales are included in production cost calculations.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.356
CANCELS FIRST REVISED SHEET NO. 8.356

Continued from Sheet No. 8.352

9. The Company's Maximum Available Generation in this methodology is defined as the maximum capacity less operating reserve requirements.

10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to the Company from all CEPs making As-Available Energy sales to the Company. In the absence of metered information on exports from the CEP making As-Available Energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known As-Available Energy purchases for that hour.

Continued to Sheet No. 8.376

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 25, 2013

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.376
CANCELS FIRST REVISED SHEET NO. 8.376

Continued from Sheet no. 8.356

SUPPLEMENTAL FUEL:

The term "supplemental fuel" refers to the variable cost for additional fuel to be delivered to Tampa Electric's generation facilities. The supplemental fuel price includes the cost of the fuel commodity at market prices plus the variable cost to deliver the commodity to the generation facility. Market prices for coal, oil and natural gas are based on published indexes or current market activity for commodities of comparable quality to those used in Tampa Electric's generation facilities.

AVOIDED ENERGY COST CALCULATIONS:

Example: 1 Off-system purchases are not being made. The Company's generation is capable of carrying its native load and firm sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with As-Available Energy on an hour by hour basis when no off-system purchases are taking place is as follows:

The 1st calculation determines the Company's production cost without the benefit of cogeneration.

Continue to Sheet No. 8.378

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: July 13, 2010

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.378
CANCELS ORIGINAL SHEET NO. 8.378

In these instances, the $/MWH price that the Company will pay the CEPs is determined by calculating the production cost at 2 load levels.

The 2nd calculation determines the Company's production cost with the benefit of cogeneration.

After each of the 2 calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the 2 calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an XMW block equivalent to the combined actual hourly generation delivered to the Company from all CEPs making As-Available Energy sales to the Company. In the absence of metered information on exports from the CEP making As-Available Energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate Designated Avoided Unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate Designated Avoided Unit(s), firm energy purchases from CEPs shall be treated as as-available energy for the purposes of determining the XMW block size only during the periods that the appropriate Designated Avoided Unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" CEP MWs purchased during the hour to determine payment to each CEP supplying As-Available Energy, and each CEP supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit 1.

Example 2 Off-system purchases are not being made. The Company's generation can only carry its native load and firm sales with the CEP contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with As-Available Energy on an hour by hour basis whenever the Company is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that the Company will pay the CEPs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit 2.

In the situation where the Company's generation is not fully dispatched, and additional generation capability is available to price a portion of the CEP block, then the CEP block will be priced at a combination of the difference between the Company's production cost at 2 load levels as previously defined and at system lambda. See Exhibit 3.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.382
CANCELS ORIGINAL SHEET NO. 8.382

Example 3 Off-system purchases are being made to serve native load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with As-Available Energy on an hour by hour basis whenever the Company is making off-system purchases for native load is as follows:

In this instance, the $/MWH price that the Company will pay is determined by applying the highest incremental cost of the off-system purchases to the CEP block. See Exhibit 4.

DELIVERY VOLTAGE ADJUSTMENT: A credit for avoided line losses reflecting the voltage at which generation by the CEPs is received is included in the Company's procedure for the determination of incremental avoided energy cost associated with As-Available Energy. Tampa Electric uses the adjustment factors shown on Sheet No. 8.306 for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based on the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH

Adjustment Factor for Line Losses:
1.0561

The Actual Incremental Hourly Avoided Energy Cost adjusted for avoided line losses associated with As-Available Energy provided to the Company would then become, in this example, $15.63/MWH.

"IDENTIFIABLE" INCREMENTAL VARIABLE O&M: Tampa Electric's methodology for determining incremental avoided energy costs associated with As-Available Energy includes a procedure for calculating "identifiable" incremental variable O&M (VOM) expense.

A VOM rate ($/MWH) is calculated annually for each Tampa Electric generating group. A generating group comprises units of the same type with similar size and operating characteristics (e.g., Big Bend coal units, Bayside CCs, Polk IGCC, all 180 MW CTs, etc.). The VOM rate for a generating group is calculated by dividing the previous year's identifiable VOM expenses for the group by the previous year's generation in megawatt-hours for the group.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.392

The incremental avoided energy cost associated with As-Available Energy is adjusted in each hour by the applicable VOM group rate(s) for the generation being avoided in that hour.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.394
CANCELS ORIGINAL SHEET NO. 8.394

RESERVED FOR FUTURE USE

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: July 13, 2010

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.396
CANCELS FIRST REVISED SHEET NO. 8.396

EXHIBIT 1

Example: **Off-system purchases are not being made. The Company's generation is capable of carrying its native load and firm sales.**

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation (WITHOUT CEP):

Production Cost at 1560 MWs = $20,275/hour

Second Calculation (WITH CEP):

Production Cost at 1510 MWs = $19,500/hour

Third Calculation (CEP Rate $/MWH):

Actual Hourly Avoided Energy Cost = ($20,275/hour - $19,500/hour) / (50 MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.398
CANCELS FIRST REVISED SHEET NO. 8.398

EXHIBIT 2

Example: **Off-system purchases are not being made. The Company's generation can carry its native load and firm sales only with the CEP contribution.**

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/hour

Third Calculation (CEP Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) =
($18,900/hour - $18,882.50/hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 8.402
CANCELS FIRST REVISED SHEET NO. 8.402

EXHIBIT 3

Example: **Off-system purchases are not being made to serve native load and firm sales. Available generation capacity is not fully dispatched. Without the CEP's contribution, the Company's native load and firm sales can be carried only with additional power purchases.**

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1530 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation (Without CEP):
Production Cost at 1530 MWs = $20,590/hour
Second Calculation (With CEP):
Production Cost at 1500 MWs = $20,050/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/hour) - ($20,050/hour) = $540/hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:
Production Cost at 1530 MWs = $20,590/hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) for 20 MWs =
($20,590/hour - $20,571.50/hour) X (20 MWs) = $370/hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block = ($540 + $370) / 50 MW
or
As-Available Energy Payment Rate (AEPR) = $18.20/MWH

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.404
CANCELS ORIGINAL SHEET NO. 8.404

EXHIBIT 4

Example: **Off-system purchases are being made. The Company's native load and firm sales can be carried only with additional purchase power.**

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1500 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchase[1] = 10 MWs Costing $400/hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

Or

As-Available Energy Payment Rate (AEPR) = $40/hour

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: June 19, 2012

TAMPA ELECTRIC

~~SIXTH~~ SEVENTH REVISED SHEET NO. 8.406
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 8.406

RATE SCHEDULE COG-2
APPENDIX C

~~2021~~ 2020 COMBUSTION TURBINE

This Designated Avoided Unit is a 220 MW (winter rating) natural gas-fired combustion turbine with a May 1, ~~2021~~2020, in-service date.

MINIMUM PERFORMANCE STANDARDS

In order to receive a Monthly Capacity Payment, all Contracted Capacity and Associated Energy provided by CEPs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of the Designated Avoided Unit over the term of this Standard Offer Contract. The CEP's proposed generating facility ("the Facility") as defined in the Standard Offer Contract will be evaluated against the anticipated performance of a combustion turbine, starting with the first Monthly Period following the date selected in Paragraph 6.b.ii of the Company's Standard Offer Contract.

1. **Dispatch Requirements:** The CEP shall provide peaking capacity to the Company on a firm commitment, first-call, on-call, as-needed basis. In order to receive a Contracted Capacity Payment for each calendar month that the Facility is to be dispatched, the CEP must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

2. **Dispatch Procedure:** Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 7:00 A.M. EPT, the CEP shall electronically transmit a schedule ("Available Schedule") of the hour-by-hour amounts of Contracted Capacity expected to be available from the Facility the next day ("Committed Capacity"). Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 3:00 P.M. EPT, the Company shall electronically transmit the hour-by-hour amounts of Contracted Capacity that the Company desires the CEP to dispatch from the Facility the next day based on the Available Schedule supplied at 7:00 A.M. EPT by the CEP ("Dispatch Schedule"). The CEP's Available Schedule and the Company's Dispatch

Continued to Sheet No. 8.408

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.408
CANCELS ORIGINAL SHEET NO. 8.408

Schedule for Fridays will include Saturday, Sunday, and Monday schedules. The CEP's Available Schedule and the Company's Dispatch Schedule during holiday periods will be similarly adjusted. The CEP shall control and operate the Facility in accordance with the Company's Dispatch Schedule. From time to time (i.e. during emergency conditions), the Company may be required to adjust the Dispatch Schedule or ignore scheduled levels altogether, however, each Party shall make reasonable efforts to minimize departures from the Dispatch Schedule.

3. **Automatic Generation Control:** At the Company's discretion, the CEP will operate the Facility with Automatic Generation Control (AGC) equipment, speed governors, and voltage regulators in-service, except at such times when operational constraints of the equipment prevent AGC operation.

4. **Start-up Time:** Upon notification by the Company, the CEP's Facility shall provide its capacity within 15 minutes from a cold-start condition to maximum capacity.

5. **Minimum Run Time:** Minimum run time for the CEP's unit shall be 1 hour.

BASIS FOR MONTHLY CAPACITY PAYMENT CALCULATION:

1. **Monthly Availability Factor:** The Monthly Availability Factor of the CEP's generating facility will be calculated by averaging the Hourly Availability Factors for each hour of the Monthly Period. The Hourly Availability Factor may not exceed 100% and shall be defined as the hourly Committed Capacity expressed as a percentage of Contracted Capacity to the nearest whole percentile. The CEP is required to achieve a minimum Monthly Availability Factor of 90% in order to meet the MPS and be eligible to receive a Monthly Capacity Payment. Periods of Annual Planned Maintenance will be excluded from the calculation of the Monthly Availability Factor. For purposes of calculating the Monthly Availability Factor, the CEP's Committed Capacity may not exceed its Contracted Capacity.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TECO
TAMPA ELECTRIC

FIRST REVISED SHEET NO. 8.414
CANCELS ORIGINAL SHEET NO. 8.414

2. **Monthly Capacity Factor:** In addition to the MPS for Monthly Availability, the CEP shall provide capacity into the Company's electric grid in order to meet or exceed a Monthly Capacity Factor of 80%. The Monthly Capacity Factor for the period April 1st through October 31st shall be defined as the sum of 80% of the Monthly Average On-peak Operating Factor plus 20% of the Monthly Average Off-peak Operating Factor. The Monthly Capacity Factor for the period November 1st through March 31st shall be defined as the sum of 90% of the Monthly Average On-peak Operating Factor plus 10% of the Monthly Average Off-peak Operating Factor.

   a. **Operating Factor:** The CEP shall endeavor to provide capacity in the amount dispatched by the Company. The Company may at times request capacity in an amount that exceeds the Committed Capacity as declared by CEP the previous day.

      However, the Operating Factor may not exceed 100% and shall be defined as the actual energy received during each hour that the CEP unit is dispatched by the Company divided by the lesser of the CEP's Committed Capacity or the capacity requested by the Company for that hour, expressed to the nearest whole percentile.

   b. **Monthly Average On-peak Operating Factor:** The monthly average of the Operating Factor for all hours the CEP unit has been dispatched during On-peak Hours will be termed the Monthly Average On-peak Operating Factor.

   c. **Monthly Average Off-peak Operating Factor:** The monthly average of the Operating Factor for all hours the CEP unit has been dispatched during Off-peak Hours will be termed the Monthly Average Off-peak Operating Factor.

3. **Off-Peak and On-Peak Hours:** Those weekday hours occurring April 1 through October 31, from 12:00 noon to 9:00 p.m. and November 1 through March 31, from 6:00 a.m. to 10:00 a.m. and from 6:00 p.m. to 10:00 p.m. All other weekday hours and weekends shall be deemed Off-peak Hours including the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Company shall have the right to change such On-peak Hours by providing written notice to CEP a minimum of 90 calendar days prior to such change.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: July 29, 2008

TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 8.416
CANCELS THIRD REVISED SHEET NO. 8.416

Continued from Sheet No. 8.414

4. **Annual Scheduled Maintenance:** Each year the CEP shall prepare, coordinate, and provide by April 1st all planned maintenance with the Company. The Company will review and approve annual/major scheduled maintenance by July 1st for the balance of the current year and following calendar year. A maximum of 10 days (240 hours) each year for annual maintenance and a maximum of 4 weeks (672 hours) every fifteenth year for major maintenance will be allowed. Scheduled maintenance shall not be planned during January, July, August, or December. At the option of the CEP and with written consent from the Company, scheduled outage time may be utilized during any other months to improve the CEP's Availability and Capacity Factors and such scheduled outage hours will be disregarded from the Monthly Availability Factor and Capacity Factor calculations. However, once allowable maintenance hours have been utilized, all other hours during the year will be considered in Availability and Capacity Factor calculations.

5. **Monthly Capacity Payment:** Starting with the CEP's Commercial In-Service Date, for months when the CEP unit has been dispatched (provided that CEP has achieved at least a 90% Monthly Availability Factor), the Monthly Capacity Payment for each Monthly Period shall be calculated according to the following:

   a. In the event that the Monthly Capacity Factor is less than 80%, no Monthly Capacity Payment shall be paid to the CEP. That is:

   $$MCP = \$0$$

   b. In the event that the Monthly Capacity Factor is greater than or equal to 80% but less than 90%, the Monthly Capacity Payment shall be calculated from the following formula:

   $$MCP = [(BCC) \times (.02 \times (CF - 45))] \times CC$$

Continued on Sheet No. 8.418

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: July 21, 2015

TAMPA ELECTRIC

ORIGINAL SHEET NO. 8.418

c. In the event that the Monthly Capacity Factor is greater than or equal to 90%, the Monthly Capacity Payment shall be calculated from the following formula:

MCP= (BCC) x CC

Where:

MCP	=	Monthly Capacity Payment in dollars.
BCC	=	Base Capacity Credit in \$/KW-Month *(as exemplified by the Payment Schedules included in this Appendix for the minimum contract term under Capacity Payment Options 1, 2, 3 and 4.)*
CC	=	Contracted Capacity in KW
CF	=	Monthly Capacity Factor; or

During April 1 - October 31:
= 80% x Monthly Average On-peak Operating Factor + 20% x Monthly Average Off-peak Operating Factor

During November 1 - March 31:
= 90% x Monthly Average On-peak Operating Factor + 10% x Monthly Average Off-peak Operating Factor

6. **Non-Dispatch Condition:** The CEP may be entitled to a Monthly Capacity Payment (BCC x CC) even if the CEP's unit was not dispatched by the Company during a Monthly Period. In this instance however, in order to cover the Company's operating reserve criteria, the CEP unit must have achieved a minimum Monthly Availability Factor of 90% for the Monthly Period to be eligible to receive a Monthly Capacity Payment.

In the event the CEP unit is dispatched during one but not the other (On-peak vs. Off- peak) period during the month, the CEP's Monthly Average Operating Factor for the "non-dispatched" period will be set equal to the Monthly Average Operating Factor achieved during the "dispatched" period, for the purpose of calculating the Monthly Capacity Factor, as defined in Paragraph 2 above.

The CEP may be entitled to a Monthly Capacity Payment when the CEP's unit is out of service during the month for allowable scheduled maintenance in accordance with the Paragraph 4 above.

ISSUED BY: C. R. Black, President

DATE EFFECTIVE: May 22, 2007

TECO
TAMPA ELECTRIC

~~EIGHTH~~ NINTH REVISED SHEET NO. 8.422
CANCELS ~~SEVENTH~~ EIGHT REVISED SHEET NO. 8.422

Continued from Sheet No. 8.418

PARAMETERS FOR AVOIDED CAPACITY COSTS

Beginning with the in-service date (5/1/2021) of the Company's Designated Avoided Unit, a 220MW (Winter Rating) natural gas-fired Combustion Turbine, for a 1 year deferral:

			VALUE
VAC_m	=	Company's monthly value of avoided capacity, \$/kW/month, for each month of year n	~~7.29~~6.40
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year	~~1.4600~~1.3834
I_n	=	total direct and indirect cost, in mid-year \$/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit(s) been constructed	~~744.46~~795.20
O_n	=	total fixed operation and maintenance expense for the year n, in mid-year \$/kW/year, of the Designated Avoided Unit(s);	~~13.49~~13.16
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s)	~~2.1~~2.5%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);	~~2.5~~2.4%
r	=	discount rate, defined as the Company's incremental after tax cost of capital;	~~7.29~~6.98%

Continued to Sheet No. 4.424

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

~~EIGHTH~~ NINTH REVISED SHEET NO. 8.424
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 8.424

Continued from Sheet No. 8.422

L	=	expected life of the Designated Avoided Unit(s); and	~~25~~30
n	=	year for which the Designated Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.	~~2021~~2020
A_m	=	monthly early capacity payments to be made to the CEP for each month of the contract year n, in $/kW/month, if payments start in 2015;	~~3.41~~3.78
m	=	Earliest year in which early capacity payments to the CEP may begin;	~~2015~~2016*
F	=	the cumulative present value, in the year contractual payments will begin, of the avoided capital cost component of capacity payments over the term of the contract which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s);	~~392.09~~404.32*
t	=	the term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;	~~16~~14*

** Actual values will be determined based on the capacity payment start date and contract term selected by the CEP.*

Continued to Sheet No. 8.426

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

~~EIGHTH~~ NINTH REVISED SHEET NO. 8.426
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 8.426

Continued from Sheet No. 8.424

2021 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
NON-LEVELIZED PAYMENT OPTIONS

		OPTION 1	OPTION 2					
		NORMAL PAYMENT	EARLY PAYMENT					
CONTRACT YEAR		Starting 5/1/21	Starting 5/1/20	Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16	Starting 5/1/15
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/15	4/30/16							3.41
5/1/16	4/30/17						3.82	3.48
5/1/17	4/30/18					4.29	3.90	3.56
5/1/18	4/30/19				4.85	4.39	3.98	3.63
5/1/19	4/30/20			5.52	4.96	4.48	4.07	3.71
5/1/20	4/30/21		6.32	5.64	5.06	4.58	4.16	3.79
5/1/21	4/30/22	7.29	6.45	5.76	5.17	4.68	4.25	3.87
5/1/22	4/30/23	7.45	6.59	5.88	5.29	4.78	4.34	3.96
5/1/23	4/30/24	7.61	6.73	6.01	5.40	4.88	4.43	4.04
5/1/24	4/30/25	7.77	6.88	6.14	5.52	4.99	4.53	4.13
5/1/25	4/30/26	7.94	7.03	6.27	5.64	5.09	4.63	4.22
5/1/26	4/30/27	8.11	7.18	6.41	5.76	5.20	4.73	4.31
5/1/27	4/30/28	8.29	7.34	6.55	5.88	5.32	4.83	4.40
5/1/28	4/30/29	8.47	7.50	6.69	6.01	5.43	4.93	4.50
5/1/29	4/30/30	8.65	7.66	6.83	6.14	5.55	5.04	4.60
5/1/30	4/30/31	8.84	7.82	6.98	6.27	5.67	5.15	4.70

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

~~EIGHTH~~ NINTH REVISED SHEET NO. 8.426
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 8.426

2020 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
NON-LEVELIZED PAYMENT OPTIONS

		OPTION 1				
		NORMAL PAYMENT	EARLY PAYMENT			
CONTRACT YEAR		Starting 5/1/20	Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/16	4/30/17					3.78
5/1/17	4/30/18				4.27	3.87
5/1/18	4/30/19			4.85	4.38	3.97
5/1/19	4/30/20		5.55	4.97	4.48	4.07
5/1/20	4/30/21	6.40	5.69	5.10	4.60	4.17
5/1/21	4/30/22	6.56	5.83	5.22	4.71	4.27
5/1/22	4/30/23	6.73	5.98	5.35	4.83	4.38
5/1/23	4/30/24	6.89	6.12	5.49	4.95	4.49
5/1/24	4/30/25	7.07	6.28	5.62	5.07	4.60
5/1/25	4/30/26	7.24	6.43	5.76	5.20	4.71
5/1/26	4/30/27	7.42	6.59	5.90	5.32	4.83
5/1/27	4/30/28	7.60	6.76	6.05	5.46	4.95
5/1/28	4/30/29	7.79	6.92	6.20	5.59	5.07
5/1/29	4/30/30	7.99	7.10	6.35	5.73	5.20

Continued to Sheet No. 8.427

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

~~THIRD~~ FOURTH REVISED SHEET NO. 8.427
CANCELS ~~SECOND~~ THIRD REVISED SHEET NO. 8.427

Continued from Sheet No. 8.426

2021 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
LEVELIZED PAYMENT OPTIONS

		OPTION 3	OPTION 4					
		LEVELIZED NORMAL PAYMENT	LEVELIZED EARLY PAYMENT					
CONTRACT YEAR		Starting 5/1/21	Starting 5/1/20	Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16	Starting 5/1/15
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/15	4/30/16							3.81
5/1/16	4/30/17						4.24	3.82
5/1/17	4/30/18					4.74	4.25	3.83
5/1/18	4/30/19				5.32	4.75	4.27	3.85
5/1/19	4/30/20			6.01	5.34	4.77	4.28	3.86
5/1/20	4/30/21		6.83	6.03	5.36	4.79	4.30	3.88
5/1/21	4/30/22	7.82	6.85	6.05	5.38	4.80	4.31	3.89
5/1/22	4/30/23	7.85	6.88	6.07	5.40	4.82	4.33	3.90
5/1/23	4/30/24	7.88	6.90	6.09	5.42	4.84	4.35	3.92
5/1/24	4/30/25	7.91	6.93	6.12	5.44	4.86	4.36	3.94
5/1/25	4/30/26	7.94	6.96	6.14	5.46	4.88	4.38	3.95
5/1/26	4/30/27	7.97	6.98	6.17	5.48	4.90	4.40	3.97
5/1/27	4/30/28	8.00	7.01	6.19	5.50	4.92	4.42	3.99
5/1/28	4/30/29	8.04	7.04	6.22	5.53	4.94	4.44	4.00
5/1/29	4/30/30	8.07	7.07	6.24	5.55	4.96	4.46	4.02
5/1/30	4/30/31	8.10	7.10	6.27	5.58	4.99	4.48	4.04

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TECO
TAMPA ELECTRIC

~~THIRD~~ FOURTH REVISED SHEET NO. 8.427
CANCELS ~~SECOND~~ THIRD REVISED SHEET NO. 8.427

2020 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
LEVELIZED PAYMENT OPTIONS

		OPTION 3				
		LEVELIZED NORMAL PAYMENT	EARLY LEVELIZED PAYMETS			
CONTRACT YEAR		Starting 5/1/20	Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/16	4/30/17					4.24
5/1/17	4/30/18				4.76	4.26
5/1/18	4/30/19			5.36	4.78	4.28
5/1/19	4/30/20		6.09	5.38	4.79	4.29
5/1/20	4/30/21	6.96	5.61	5.40	4.81	4.31
5/1/21	4/30/22	6.99	5.64	5.42	4.83	4.33
5/1/22	4/30/23	7.02	5.66	5.45	4.85	4.34
5/1/23	4/30/24	7.04	5.69	5.47	4.87	4.38
5/1/24	4/30/25	7.07	5.71	5.49	4.89	4.38
5/1/25	4/30/26	7.10	5.74	5.51	4.91	4.40
5/1/26	4/30/27	7.13	5.76	5.54	4.93	4.42
5/1/27	4/30/28	7.16	5.79	5.56	4.95	4.44
5/1/28	4/30/29	7.19	5.82	5.59	4.98	4.46
5/1/29	4/30/30	7.22	5.85	5.61	5.00	4.48

Continued to Sheet No. 8.428

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TECO
TAMPA ELECTRIC

SEVENTH REVISED SHEET NO. 8.428
CANCELS SIXTH REVISED SHEET NO. 8.428

Continued from Sheet No. 8.427

BASIS FOR MONTHLY ENERGY PAYMENT CALCULATION:

1. **Energy Payment Rate:** Prior to the in-service date of the avoided unit, the CEP's Energy Payment Rate shall be the Company's As-Available Energy Payment Rate (AEPR), as described in Appendix B. Starting the in-service date of the avoided unit, the basis for determining the Energy Payment Rate will be whether:

   a. The Company has dispatched the CEP's unit on AGC; or

   b. The Company has dispatched the CEP's unit off AGC and the CEP is operating its unit at or below the dispatched level; or

   c. The Company has dispatched the CEP's unit off AGC but the CEP is operating its unit above the dispatched level; or

   d. The Company has not dispatched the CEP's unit but the CEP is providing capacity and energy.

   Note: For any given hour the CEP unit must be operating on AGC a minimum of 30 minutes to qualify under case (a).

   The CEP's total monthly energy payment shall equal; (1) the sum of the hourly energy at the Unit Energy Payment Rate (UEPR), when the CEP's unit was dispatched by the Company, plus (2) the sum of the hourly energy at the corresponding hourly AEPR when the CEP's unit was operating at times other than when the Company dispatched the unit.

2. **Unit Energy Payment Rate:** Starting the in-service date of the avoided unit, the CEP will be paid at the UEPR for energy provided in Paragraph 1.a, Paragraph 1.b and that portion of the energy provided up to the dispatched level in Paragraph 1.c as defined above. The UEPR, which is based on the Company's Designated Avoided Unit and Heat Rate value of 10,046 Btu/kWh, will be calculated monthly by the following formula:

$$UEPR = FC + O_v$$

   where;

   O_v = Unit Variable Operation & Maintenance Expense in $/MWH.

Continued to Sheet No. 8.434

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: July 10, 2014

TAMPA ELECTRIC

~~SIXTH~~ SEVENTH REVISED SHEET NO. 8.434
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 8.434

Continued from Sheet No. 8.428

FC = Fuel Component of the Energy Payment in \$/MWH as defined by:

$$FC = \frac{\cancel{10{,}046}\ 10{,}780 \text{ Btu/kWh} \times FP}{1{,}000}$$

where;

FP = Fuel Price in \$/MMBTU determined by:

FP = GC/(1-FRP) + TC

where;

GC = Fuel Price in \$/MMBTU determined by taking the first publication of each month of Inside FERC's Gas Market Report low price quotation under the column titled "Index" for "Florida Gas Transmission Co., "Zone 2", listings.

TC = then currently approved Florida Gas Transmission (FGT) Company tariff rate in \$/MMBTU for forward haul Interruptible Market Area Transportation (ITS-1), including usage and surcharges.

FRP= then currently approved FGT Company tariff Fuel Reimbursement Charge Percentage in percent applicable to forward hauls for recovery of costs associated with the natural gas used to operate FGT's pipeline system.

3. **As-Available Energy Payment Rate (AEPR):** For energy provided and not covered under Paragraph 2 above, the AEPR will be applicable and will be based on the system avoided energy cost as defined in Appendix B.

Continued to Sheet No. 8.436

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

TAMPA ELECTRIC

~~EIGHTH~~ NINTH REVISED SHEET NO. 8.436
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 8.436

Continued from Sheet No. 8.428

PARAMETERS FOR AVOIDED UNIT ENERGY AND VARIABLE OPERATION AND MAINTENANCE COSTS

Beginning on May 1, ~~2021~~2020, to the extent that the Designated Avoided Unit(s) would have been operated had it been installed by the Company:

			VALUE
O_V	=	total variable operating and maintenance expense, in $/MWH, of the Designated Avoided Unit(s), in year n	~~2.18~~2.12
H	=	The average annual heat rate, in British Thermal Units (Btus) per kilowatt-hour (Btu/kWh), of the Designated Avoided Unit(s)	~~10,046~~10,780

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 21, 2015~~

Item 7

FILED MAY 26, 2016
DOCUMENT NO. 03231-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Lee)
Office of the General Counsel (Lherisson)

RE: Docket No. 160072-EQ – Petition for approval of new standard offer for purchase of firm capacity and energy from renewable energy facilities or small qualifying facilities and approval of tariff schedule REF-1, by Gulf Power Company.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: Staff recommends the Commission simultaneously consider Docket Nos. 160069-EQ, 160072-EQ, and 160073-EQ.

Case Background

Section 366.91(3), Florida Statutes (F.S.), requires that each investor-owned utility (IOU) continuously offers to purchase capacity and energy from renewable energy generators. Florida Public Service Commission (Commission) Rules 25-17.200 through 25-17.310, Florida Administrative Code (F.A.C.), implement the statute and require each IOU to file with the Commission by April 1 of each year, a standard offer contract based on the next avoidable fossil fueled generating unit of each technology type identified in the utility's current Ten-Year Site Plan. On April 1, 2016, Gulf Power Company (Gulf) filed a petition for approval of its standard offer contract and rate schedule REF-1 for renewable energy facilities or small qualifying facilities based on its 2016 Ten-Year Site Plan. The Commission has jurisdiction over this standard offer contract pursuant to Sections 366.04 through 366.06 and 366.91, F.S.

Discussion of Issues

Issue 1: Should the Commission approve the revised standard offer contract and schedule REF-1 filed by Gulf Power Company?

Recommendation: Yes. The provisions of Gulf's revised standard offer contract and schedule REF-1 conform to all requirements of Rules 25-17.200 through 25-17.310, F.A.C. Gulf's revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation may select the payment stream best suited to its financial needs. (Lee)

Staff Analysis: Rule 25-17.250, F.A.C., requires that Gulf, an IOU, continuously makes available a standard offer contract for the purchase of firm capacity and energy from renewable generating facilities (RF) and small qualifying facilities (QF) with design capacities of 100 kilowatts (kW) or less. Pursuant to Rule 25-17.250(1) and (3), F.A.C., the standard offer contract must provide a term of at least 10 years, and the payment terms must be based on the utility's next avoidable fossil-fueled generating unit identified in its most recent Ten-Year Site Plan or, if no avoided unit is identified, its next avoidable planned purchase.

Gulf has identified a natural gas-fired facility consisting of three combustion turbine units totaling 654 megawatt (MW), as its next planned fossil-fueled generating unit in its 2016 Ten-Year Site Plan. The projected in-service date of this facility is June 1, 2023.

The RF/QF operator may elect to make no commitment as to the quantity or timing of its deliveries to Gulf, and to have a committed capacity of zero (0) MW. Under such a scenario, the energy is delivered on an as-available basis and the operator receives only an energy payment. Alternatively, the RF/QF operator may elect to commit to certain minimum performance requirements based on the identified avoided unit, such as being operational and delivering an agreed upon amount of capacity by the in-service date of the avoided unit, and thereby becomes eligible for capacity payments in addition to payments received for energy. The standard offer contract may also serve as a starting point for negotiation of contract terms by providing payment information to an RF/QF operator, in a situation where one or both parties desire particular contract terms other than those established in the standard offer.

In order to promote renewable generation, the Commission requires the IOU to offer multiple options for capacity payments, including the options to receive early or levelized payments. If the RF/QF operator elects to receive capacity payments under the normal or levelized contract options, it will receive as-available energy payments only until the in-service date of the avoided unit (in this case June 1, 2023), and thereafter begin receiving capacity payments in addition to the energy payments. If either the early or levelized option is selected, then the operator will begin receiving capacity payments earlier than the in-service date of the avoided unit. However, payments made under the early capacity payments options tend to be lower in the later years of the contract term because the net present value (NPV) of the total payments must remain equal for all contract payment options.

Table 1 below, estimates the annual payments for each payment option available under the revised standard offer contract to an operator with a 50 MW facility operating at a capacity factor of 95 percent and meeting the minimum requirement specified in the contract to qualify for full capacity payments. Normal and levelized capacity payments begin in 2023, reflecting the projected in-service date of the avoided unit (June 1, 2023).

Table 1 – Estimated Annual Payments to a 50 MW Renewable Facility (95% Capacity Factor)

Year	Energy Payment	Capacity Payment (By Type)			
		Normal	Levelized	Early	Early Levelized
	$(000)	$(000)	$(000)	$(000)	$(000)
2017	11,905	-	-	1,325	1,556
2018	13,998	-	-	1,361	1,566
2019	15,208	-	-	1,399	1,576
2020	16,548	-	-	1,437	1,587
2021	17,380	-	-	1,477	1,598
2022	18,105	-	-	1,518	1,609
2023	19,382	1,519	1,705	1,560	1,620
2024	20,182	2,660	2,938	1,602	1,632
2025	20,976	2,733	2,958	1,647	1,644
2026	22,270	2,808	2,979	1,692	1,657
2027	23,547	2,886	3,001	1,739	1,670
2028	24,621	2,965	3,023	1,786	1,683
2029	25,931	3,047	3,046	1,836	1,697
2030	26,360	3,131	3,069	1,886	1,711
2031	27,284	3,217	3,093	1,938	1,725
2032	28,443	3,306	3,118	1,992	1,740
2033	29,863	3,397	3,143	2,046	1,755
2034	31,495	3,490	3,169	2,103	1,771
2035	32,656	3,586	3,196	2,161	1,787
2036	34,564	3,685	3,223	2,220	1,803
Total	460,717	42,431	41,660	34,724	33,384
NPV (2017$)	232,745	18,343	18,343	18,343	18,343

Gulf's standard offer contract and schedule REF-1, in type-and-strike format, are included as Attachment A. All of the changes made to the tariff sheets are consistent with the updated avoided unit. Revisions include updates to the avoided unit, dates, and payment information which reflect the current economic and financial assumptions for the avoided unit costs.

Conclusion

The provisions of Gulf's revised standard offer contract and schedule REF-1 conform to all requirements of Rules 25-17.200 through 25-17.310, F.A.C. The revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation my select the payment stream best suited to its financial needs. Staff recommends that Gulf's revised standard offer contract and schedule REF-1 be approved as filed.

Issue 2: Should this docket be closed?

Recommendation: Yes. This docket should be closed upon issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, Gulf's standard offer contract may subsequently be revised. (Lherisson)

Staff Analysis: This docket should be closed upon the issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, Gulf's standard offer contract may subsequently be revised.

Standard Offer Contract (Schedule REF-1)

Gulf Power Company

Revisions in underline and strike-through format
shown the following sheets:

9.82, 9.85, 9.86, 9.88 and 9.103

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Third Revised Sheet No. 9.81
Canceling Second Revised Sheet No. 9.81

STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM A RENEWABLE ENERGY FACILITY OR SMALL QUALIFYING FACILITY

(Schedule REF-1)

PAGE	EFFECTIVE DATE
1 of 16	July 17, 2014

For purposes of this Rate Schedule the term "Renewable Energy Facility" means a facility that produces electrical energy from one or more of the sources stated in Florida Public Service Commission (FPSC) Rule 25-17.210 (1), Florida Administrative Code (F.A.C.). Also, the term "Small Qualifying Facility" means a facility with a design capacity of 100 KW or less as defined in FPSC Rule 25-17.080, F.A.C. Both "Renewable Energy Facility" and "Small Qualifying Facility" are herein referred to as "Facility".

AVAILABILITY:

Gulf Power Company (Company) will purchase firm capacity and energy under this schedule from any Facility that produces electrical energy for delivery to the Company, irrespective of its location, which is either directly or indirectly interconnected with the Company under the provisions of this schedule. The offer to purchase such capacity and energy is continuously available to any Facility and will remain open until revised by the Company upon approval of the FPSC or until closed pursuant to FPSC Rule 25-17.250 (2), F.A.C. The Company may negotiate and contract with any Facility, irrespective of its location, which is either directly or indirectly interconnected with the Company for the purchase of firm capacity and energy pursuant to FPSC Rules 25-17.240 and 25-17.0832, F.A.C.

APPLICABILITY:

This offer is applicable to any Facility meeting the requirements of FPSC Rules 25-17.210, 25-17.220, and/or 25-17.0832, F.A.C., irrespective of its location, producing capacity and energy for sale to the Company on a firm basis pursuant to the terms and conditions of this schedule and the Company's "Renewable Standard Offer Contract." Firm capacity and energy are described by the FPSC in its Rule 25-17.0832, F.A.C., and are produced and sold by a Facility pursuant to a negotiated or Renewable Standard Offer Contract and subject to certain contractual provisions as to quantity, time, and reliability of delivery.

CHARACTER OF SERVICE:

The character of service for purchases from Facilities directly interconnected with the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. The character of service for purchases from Facilities indirectly interconnected with the Company shall be three phase, 60 hertz, alternating current at the voltage level available at the interchange point between the Company and the utility delivering firm capacity and energy from the Facility.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
~~Seventh~~Eighth Revised Sheet No. 9.82
Canceling ~~Sixth~~Seventh Revised Sheet No. 9.82

PAGE	EFFECTIVE DATE
2 of 16	July 21, 2015

(Continued from Schedule REF-1, Sheet No. 9.81)

LIMITATIONS:

Purchases under this schedule are subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C., and are limited to those Facilities that:

A. Beginning upon the date, as prescribed by the FPSC, that a Renewable Standard Offer is deemed available, execute the Company's Renewable Standard Offer Contract for the purchase of firm capacity and energy; and

B. Commit to commence deliveries of firm capacity and energy no later than the date specified by the Facility's owner or representative, or the anticipated in-service date of the Company's generating facility or purchased power resource ("Avoided Unit or Resource") that is designated herein. Such deliveries will continue for a minimum of ten (10) years from the anticipated in-service date of the Company's Avoided Unit or Resource up to a maximum of the life of the Company's Avoided Unit or Resource.

DETERMINATION OF FACILITY'S COMMITTED CAPACITY VALUE

Prior to execution of a Renewable Standard Offer Contract, or negotiated contract, between the Company and a Facility, the Company will determine the Facility's capacity value in relation to the Company's Avoided Unit or Resource during the term of the contract as provided in FPSC Rules 25-17.240 (2), 25-17.250 (1), and 25-17.0832 (3) and (4) F.A.C. The "Committed Capacity" will be used as the basis for capacity payments to be received by the Facility from the Company during the term of the Renewable Standard Offer Contract.

RATES FOR PURCHASES BY THE COMPANY

Firm capacity is purchased in accordance with the provisions of paragraph A below at a unit cost, in dollars per kilowatt per month, based on the value of the Avoided Unit or Resource that Gulf has designated below for purposes of the Renewable Standard Offer. The Avoided Unit is currently designated as ~~866~~654 MWs of Combustion Turbine generation with a June 1, 2023 anticipated in-service date. Energy is purchased at a unit cost, in cents per kilowatt-hour, at the Company's energy rates in accordance with the provisions of paragraph B below.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Original Sheet No. 9.83

PAGE	EFFECTIVE DATE
3 of 16	May 22, 2007

(Continued from Schedule REF-1, Sheet No. 9.82)

A. Firm Capacity Rates

Four options, 1, 2, 3, and 4, as set forth in this paragraph, are available to calculate payments for firm capacity that is produced by the Facility and delivered to the Company. The capacity payment will be the product of the Facility's Committed Capacity and the applicable rate from the Facility's chosen capacity payment option. Once selected, an option shall remain in effect for the term of the contract with the Company. Tariff Sheet 9.85 contains the monthly rate per kilowatt in accordance with Options 1 through 4, of firm capacity the Facility has contractually committed to deliver to the Company and is based on the minimum contract term for an agreement pursuant to this Rate Schedule which extends ten (10) years after the anticipated in-service date of the Company's Avoided Unit or Resource. Payment schedules for other options specified within will be made available by the Company within thirty days (30) days if requested by a Facility. At a maximum, firm capacity and energy shall be delivered for a period of time equal to the anticipated plant life of the Avoided Unit or Resource, commencing with the anticipated in-service date of the Avoided Unit or Resource.

In addition to capacity payment Options 1 through 4 below, the Facility may elect a payment stream for the capital component of the Company's Avoided Unit or Resource, including front-end loaded capacity payments, that best meets the Facility's financing requirements. Early capacity payments consisting of the capital component of the Company's Avoided Unit or Resource may, at the election of the Facility, commence any time after the actual in-service date of the Facility and before the anticipated in-service date of the Company's Avoided Unit or Resource. Regardless of the payment stream elected by the Facility, the cumulative present value (CPV) of the capital cost payments made to the Facility over the term of the Renewable Standard Offer Contract shall not exceed the CPV of the capital cost payments which would have been made to the Facility pursuant to FPSC Rule 25-17.0832 (4)(g)(1), F.A.C. Fixed operation and maintenance expense shall be calculated in accordance with FPSC Rule 25-17.0832 (6) F.A.C.

Option 1 - Value of Deferral Capacity Payments - Value of Deferral Capacity Payments shall commence on the anticipated in-service date of the Company's Avoided Unit or Resource, provided the Facility is delivering firm capacity and energy to the Company. Capacity payments under this option shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Avoided Unit or Resource, and shall be equal to the value of the year-by-year deferral of the Avoided Unit or Resource, calculated in conformance with the applicable provisions of FPSC Rule 25-17.0832 (4)(g)(1), F.A.C.

Option 2 - Early Capacity Payments - Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Company's Avoided Unit or Resource with an in-service date specified above. The Facility shall select

ISSUED BY: Susan Story

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Original Sheet No. 9.84

PAGE	EFFECTIVE DATE
4 of 16	May 22, 2007

(Continued from Schedule REF-1, Sheet No. 9.83)

the month and year in which the delivery of firm capacity and energy to the Company is to commence and capacity payments are to start. Early Capacity Payments shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Avoided Unit or Resource. Avoided capacity payments shall be calculated in conformance with the applicable provisions of FPSC Rule 25-17.0832 (4)(g)(2), F.A.C. At the option of the Facility, Early Capacity Payments may commence at any time after the specified earliest capacity payment date and before the anticipated in-service date of the Company's Avoided Unit or Resource provided the Facility is delivering firm capacity and energy to the Company. Where Early Capacity Payments are elected, the cumulative present value of the capacity payments made to the Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Facility had such payments been made pursuant to Option 1.

Option 3 - Levelized Capacity Payments - Levelized Capacity Payments shall commence on the anticipated in-service date of the Company's Avoided Unit or Resource, provided the Facility is delivering firm capacity and energy to the Company. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with the applicable provisions of FPSC Rule 25-17.0832 (4)(g)(3), F.A.C. The fixed operation and maintenance portion of the capacity payment shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expense associated with the Company's Avoided Unit or Resource. Where Levelized Capacity Payments are elected, the cumulative present value of the capacity payments made to the Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Facility had such payment been made pursuant to Option 1.

Option 4 - Early Levelized Capacity Payments - Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Company's Avoided Unit or Resource with an in-service date specified above. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with the applicable provisions of FPSC Rule 25-17.0832 (4)(g)(4), F.A.C. The fixed operation and maintenance portion of the capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expense associated with the Company's Avoided Unit or Resource. At the option of the Facility, Early Levelized Capacity Payments shall commence at any time after the specified earliest capacity payment date and before the anticipated in-service date of the Company's Avoided Unit or Resource provided the Facility is delivering firm capacity and energy to the Company. The Facility shall select the month and year in which the delivery of firm capacity and energy to the Company is to commence and capacity payments are to start. Where Early Levelized Capacity Payments are elected, the cumulative present value of the

ISSUED BY: Susan Story

GULF POWER
A SOUTHERN COMPANY

Section No. IX
~~Eighth~~Ninth Revised Sheet No. 9.85
Canceling ~~Seventh~~Eighth Revised Sheet No. 9.85

PAGE	EFFECTIVE DATE
9 of 16	[illegible]

(Continued from Schedule REF-1, Sheet No. 9.84)

capacity payments made to the Facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the Facility had such payments been made pursuant to Option 1.

All capacity payments made by the Company prior to the anticipated in-service date of the Company's Avoided Unit or Resource are considered "Early Payments". The owner, owner's representative, or operator of the Facility, as designated by the Company, shall secure its obligation to repay, with interest, the accumulated amount of Early Payments to the extent that the cumulative present value of the capacity payments made to the Facility over the term of the contract exceeds the cumulative present value of the capacity payments which would have been made to the Facility had such payments been made pursuant to Option 1, or to the extent that annual firm capacity payments made to the Facility in any year exceed that year's annual value of deferring the Company's Avoided Unit or Resource in the event the Facility defaults under the terms of its Renewable Standard Offer Contract with the Company. The Company will provide to the Facility monthly summaries of the total outstanding balance of such security obligations. A summary of the types of security instruments which are generally acceptable to the Company is set forth in Paragraph C of the SPECIAL PROVISIONS Section below.

**MONTHLY CAPACITY PAYMENT RATE (MCR)
BASED ON GULF'S CURRENTLY SPECIFIED
AVOIDED UNIT OR RESOURCE**

June - May Contract Period	Option 1 Normal $/KW-MO	Option 2 Early $/KW-MO	Option 3 Levelized $/KW-MO	Option 4 Early Levelized $/KW-MO
~~2015 to 2016~~	~~0.00~~	~~1.75~~	~~0.00~~	~~2.01~~
2016 to 2017	0.00	~~1.80~~1.86	0.00	~~2.02~~2.14
2017 to 2018	0.00	~~1.84~~1.92	0.00	~~2.03~~2.16
2018 to 2019	0.00	~~1.89~~1.97	0.00	~~2.04~~2.17
2019 to 2020	0.00	~~1.94~~2.02	0.00	~~2.05~~2.19
2020 to 2021	0.00	~~1.99~~2.08	0.00	~~2.07~~2.20
2021 to 2022	0.00	~~2.04~~2.14	0.00	~~2.08~~2.22
2022 to 2023	0.00	~~2.09~~2.19	0.00	~~2.09~~2.23
2023 to 2024	~~4.59~~4.36	~~2.14~~2.26	~~4.86~~4.74	~~2.11~~2.25
2024 to 2025	~~4.71~~4.48	~~2.20~~2.32	~~4.89~~4.77	~~2.12~~2.27
2025 to 2026	~~4.83~~4.61	~~2.25~~2.38	~~5.02~~4.80	~~2.13~~2.28
2026 to 2027	~~4.95~~4.73	~~2.31~~2.45	~~5.05~~4.84	~~2.15~~2.30
2027 to 2028	~~5.07~~4.86	~~2.37~~2.51	~~5.08~~4.87	~~2.16~~2.32
2028 to 2029	~~5.20~~5.00	~~2.43~~2.58	~~5.11~~4.91	~~2.18~~2.34
2029 to 2030	~~5.33~~5.14	~~2.49~~2.65	~~5.15~~4.95	~~2.20~~2.36
2030 to 2031	~~5.47~~5.28	~~2.55~~2.73	~~5.18~~4.99	~~2.21~~2.38
2031 to 2032	~~5.61~~5.42	~~2.61~~2.80	~~5.22~~5.03	~~2.23~~2.40
2032 to 2033	~~5.75~~5.57	~~2.68~~2.88	~~5.26~~5.07	~~2.25~~2.42

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
~~Original~~First Revised Sheet No. 9.86
Canceling Original Sheet No. 9.86

PAGE	EFFECTIVE DATE
6 of 16	May 29, 2007

(Continued from Schedule REF-1, Sheet No. 9.85)

The capacity payment for a given month will be added to the energy payment for such month and tendered by the Company to the Facility as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

B. Energy Rates

1. Payments Starting On In-Service Date of Avoided Unit or Resource: The Facility shall be paid at the Avoided Unit or Resource's energy rate for all energy delivered to the Company during each hour of the monthly billing period in which the Avoided Unit or Resource would have operated had the unit been installed. For each hour of the monthly billing period in which the Avoided Unit or Resource would not have operated, the Facility shall be paid for all energy delivered to the Company during that hour at the lesser of the Company's As-Available energy rate as described in its Rate Schedule COG-1, Sheet 9.3 or the Avoided Unit or Resource's energy rate.

   The Avoided Unit or Resource's energy rate, in cents per kilowatt-hour, shall be the product of the Avoided Unit or Resource's applicable fuel cost and heat rate, plus the applicable variable operation and maintenance expense. All energy purchases shall be adjusted for losses from the point of metering to the point of interconnection.

~~All energy purchases shall be adjusted for losses from the point of metering to the point of interconnection.~~

2. Payments Prior To In-Service Date of Avoided Unit or Resource: The Company's As-Available energy rate, as described in Rate Schedule COG-1, Sheet 9.3, will be applied to all energy delivered by the Facility to the Company prior to the Avoided Unit or Resource's in-service date. As-available energy payments to the Facility shall be based on the sum, over all hours of the monthly billing period in which the Facility delivers energy to the Company, of the product of each hour's As-Available energy rate times the energy received by the Company during that hour. All energy purchases shall be adjusted for losses from the point of metering to the point of interconnection.

3. Fixed Energy Payments: Upon request by the Facility, the Company will provide the following fixed payment options for energy delivered to the Company.

   a. As-Available energy payments made prior to the Avoided Unit or Resource's in-service date shall be based on the Company's year-by-year projection of system incremental fuel costs, prior to hourly economy energy sales to other utilities, based on normal weather and fuel market conditions. A fuel market volatility risk premium may be added to the energy payments upon mutual agreement between Company and Facility regarding the method or mechanism for determining such risk premium.

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Original Sheet No. 9.87

PAGE	EFFECTIVE DATE
7 of 16	May 22, 2007

(Continued from Schedule REF-1, Sheet No. 9.86)

b. Firm Energy Payments: Subsequent to the determination of full avoided cost and subject to provisions of FPSC Rule 25.17-0832 (3) (a) through (d), a mutually agreed portion of the Avoided Unit or Resource's base energy costs shall be fixed and amortized on a present value basis over the term of the contract starting as early as the in-service date of the Facility. Base energy costs associated with the Avoided Unit or Resource shall mean the energy costs that would have resulted had the Avoided Unit or Resource been operated.

PERFORMANCE CRITERIA

Payments from the Company for firm capacity are conditioned on the Facility's ability to maintain the following performance criteria:

A. <u>Commercial In-Service Date</u>

Capacity payments shall not commence until the Facility has attained and demonstrated, commercial in-service status. The commercial in-service date of a Facility shall be defined as the first day of the month following the successful completion of a test in which the Facility maintains an hourly kilowatt (KW) output, as metered at the point of interconnection with the Company, equal to or greater than the Facility's Committed Capacity specified in its Renewable Standard Offer Contract for an entire test period. A Facility shall coordinate the selection of the test period with the Company to ensure that the performance of the Facility during this period is reflective of day-to-day operational conditions likely to be experienced by the Company's Avoided Unit or Resource if it were to be in actual operation during a similar period.

B. <u>Facility Capacity Availability Requirement</u>

Payments for firm capacity shall be made monthly in accordance with the capacity payment rate option selected by the Facility, subject to the condition that, beginning on the Avoided Unit or Resource's in-service date and continuing through the remainder of the contract term, the Facility maintains the minimum Equivalent Availability Factor (EAF) that is defined in the ANNUAL CAPACITY AVAILABILITY FACTOR DETERMINATION Section below for each 12 month performance period ending August 31. Failure to satisfy this availability requirement shall result in an obligation for repayment by the Facility of an amount calculated in accordance with the Capacity Repayment procedure contained in Paragraph A of the ANNUAL CAPACITY AVAILABILITY FACTOR DETERMINATION Section below.

ISSUED BY: Susan Story

GULF POWER
A SOUTHERN COMPANY

Section No. IX
~~Third~~Fourth Revised Sheet No. 9.88
Canceling ~~Second~~Third Revised Sheet No. 9.88

PAGE	EFFECTIVE DATE
9 of 16	July 10, 2014

(Continued from Schedule REF-1, Sheet No. 9.87)

For the first performance period of the Renewable Standard Offer Contract, the repayment obligation shall be determined as below, except that the period for which the availability requirement applies and which is subject to repayment shall begin on the Avoided Unit or Resource's in-service date and end on the August 31 immediately following the Avoided Unit or Resource's in-service date.

In addition to the foregoing, when early capacity payments have been elected and received, the failure of the Facility to satisfy the availability requirement set forth below shall also result in an obligation for additional repayments by the Facility to the Company. The amount of such additional repayment shall be equal to the difference between: (1) what the Facility would have been paid during the previous twelve months ending August 31 had it elected the normal payment option; and (2) what it was paid pursuant to the payment option selected. Prior to the in-service date of the Avoided Unit or Resource, all performance requirements as listed in Paragraph B of the following Section will apply at the time initial capacity and energy deliveries from the Facility commence.

ANNUAL CAPACITY AVAILABILITY FACTOR DETERMINATION

In October following each performance period, the Company will calculate the availability of the Facility over the most recent twelve month performance period ending August 31. For purposes of this Schedule, the annual capacity availability is determined using the NERC Generation Availability Data System (GADS) formula for EAF that is shown below. The Facility will be entitled to retain capacity payments received during the annual period if an EAF of 95% is maintained for each performance period. If the Facility fails to maintain this EAF, then the Facility will repay the Company a portion of the performance period capacity payments as calculated in accordance with the procedure in Paragraph A.

$EAF = \{[AH - (EUDH + EPDH + ESEDH)] / PH \} X 100 (\%)$ where,

AH = Available Hours
Sum of all SH, RSH, Pumping Hours, and Synchronous Condensing Hours.

EPDH = Equivalent Planned Derated Hours
Product of the Planned Derated Hours and the Size of Reduction, divided by the NMC.

ESEDH = Equivalent Seasonal Derated Hours
NMC less the NDC, times the Available Hours (AH), divided by the NMC.

EUDH = Equivalent Unplanned Derated Hours
Product of the Unplanned Derated Hours and the Size of Reduction, divided by the NMC.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.89
Canceling Third Revised Sheet No. 9.89

PAGE	EFFECTIVE DATE
9 of 15	July 10, 2014

(Continued from Schedule REF-1, Sheet No. 9.88)

NDC = Net Dependable Capacity
NMC modified for ambient limitations.

NMC = Capacity a unit can sustain over a specified period when not restricted by ambient conditions or equipment deratings, minus the losses associated with station service or auxiliary loads.

PH = Period Hours
Number of hours a unit was in the active state. A unit generally enters the active state on its commercial date.

RSH = Reserve Shutdown Hours
Total number of hours the unit was available for service but not electrically connected to the transmission system for economic reasons.

SH = Service Hours
Total number of hours a unit was electrically connected to the transmission system.

A. Capacity Repayment Calculation

The following conditions will determine the amount of the Facility's Capacity Repayment obligation:

1. If EAF is greater than or equal to 95%, then;

   Capacity Repayment (CR) = 0

2. If EAF is less than 95% but equal to or greater than 60%, then;

   CR = [Monthly Capacity Rate (MCR) X Committed Capacity (CC) X Months In Performance Period (MPP) X ((95-EAF)/95)

3. If EAF is less that 60%, then;

   CR = MCR X CC X MPP

B. Additional Performance Criteria

1. The Facility shall provide monthly generation estimates by October 1 for the next calendar year; and
2. The Facility shall promptly update its yearly generation schedule when any changes are determined necessary; and

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
First Revised Sheet No. 9.90
Canceling Original Sheet No. 9.90

PAGE	EFFECTIVE DATE
10 of 105	June 14, 2011

(Continued from Schedule REF-1, Sheet No. 9.89)

3. The Facility shall agree to reduce generation or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and
4. The Facility shall coordinate scheduled outages with the Company; and
5. The Facility shall comply with the reasonable requests of the Company regarding daily or hourly communications and;
6. The Facility must promptly notify the Company of its inability to supply any portion of its full Committed Capacity from the Facility. Failure of the Facility to notify the Company of a known derating or inability to meet its Committed Capacity obligation may, at the sole discretion of the Company, result in a determination of non-performance.

DELIVERY VOLTAGE ADJUSTMENT

Energy payments to Facilities directly interconnected with the Company shall be adjusted according to the delivery voltage by dividing the energy delivered at that voltage by the following factors:

Transmission Voltage Delivery	1.01801#
Substation Voltage Delivery	1.03208##
Primary Voltage Delivery	1.05862###
Secondary Voltage Delivery	1.08576####

Any Facility interconnected at a voltage of 46 KV or above.

Any Facility interconnected at a voltage on the low side of a substation below 46 KV and above 4 KV. This substation, where the Facility takes electricity on the low side, shall have transmission voltage on the high side (115, 69, or 46 KV) and distribution voltage on the low side (25, 12, or 4 KV).

Any Facility interconnected at a distribution voltage, 4 to 25 KV inclusive.

Any Facility interconnected at a voltage below 4 KV.

METERING REQUIREMENTS

Facilities directly interconnected with the Company shall pay the Company for meters required hereunder. Hourly demand recording meters shall be required for each individual generator unit comprising a Facility with a total installed capacity of 100 KW or more. Where the total installed capacity of the Facility is less than 100 KW, the Facility may select from either hourly demand recording meters, dual kilowatt-hour register time-of-day meters or standard kilowatt-hour meters. Meters shall be installed to measure the energy production from each generating unit of the

ISSUED BY: Mark Crosswhite

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.91
Canceling Third Revised Sheet No. 9.91

PAGE	EFFECTIVE DATE
11 of 16	July 17, 2014

(Continued from Schedule REF-1, Sheet No. 9.90)

Facility as well as net delivered energy at the point of interconnection. Purchases from Facilities indirectly interconnected with the Company shall be measured as the quantities scheduled for interchange to the Company by the utility delivering firm capacity and energy to the Company.

BILLING OPTIONS

The Facility may elect to make either simultaneous purchases and sales or net sales. The decision to change billing methods can be made once every twelve (12) months coinciding with the next Fuel and Purchased Power Cost Recovery Factor billing period providing the Company is given at least thirty days written notice before the change is to take place. In addition, allowance must be made for the installation or alteration of needed metering or interconnection equipment for which the Facility must pay; and such purchases and/or sales must not abrogate any provisions of the tariff or contract with the Company.

A statement covering the charges and payments due the Facility is rendered monthly, and payment normally is made by the twentieth business day following the end of the billing period.

CHARGES TO THE FACILITY

A. Base Charges

Monthly base charges for meter reading, billing and other applicable administrative costs shall be equal to the base charge applicable to a customer receiving retail service under similar load characteristics.

B. Interconnection Charge for Non-Variable Utility Expenses

The Facility, in accordance with Rule 25-17.087, F.A.C., shall bear the cost required for interconnection including the cost of metering and the cost of accelerating construction of any transmission or distribution system improvements required in order to accommodate the location chosen by the Facility. The Facility shall have the option of payment in full for interconnection or making equal monthly installment principle payments over a thirty-six (36) month period plus interest at the thirty (30) day commercial paper rate.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.92
Canceling First Revised Sheet No. 9.92

PAGE	EFFECTIVE DATE
12 of 16	July 17, 2014

(Continued from Schedule REF-1, Sheet No. 9.91)

C. Interconnection Charge for Variable Utility Expenses

The Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include (a) the Company's inspections of the interconnection, and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Facility if no sales to the Company were involved.

D. Taxes and Assessments

The Facility shall hold the Company and its general body of ratepayers harmless from the effects of any additional taxes, assessments or other impositions that arise as a result of the purchase of energy and capacity from the Facility in lieu of other energy and capacity. Any savings in regards to taxes or assessments shall be included in the avoided cost payments made to the Facility to the extent permitted by law. In the event the Company becomes liable for additional taxes, assessments or impositions arising out of its transactions with the Facility under this tariff schedule or any related interconnection agreement or due to changes in laws affecting the Company's purchases of energy and capacity from the Facility occurring after the execution of an agreement under this tariff schedule and for which the Company would not have been liable if it had produced the energy and/or constructed facilities sufficient to provide the capacity contemplated under such agreement itself, the Company may bill the Facility monthly for such additional expenses or may offset them against amounts due to the Facility from the Company. Any savings in taxes, assessments or impositions that accrue to the Company as a result of its purchase of energy and capacity under this tariff schedule that are not already reflected in the avoided energy or avoided capacity payments made to the Facility hereunder, shall be passed on to the Facility to the extent permitted by law without consequential penalty or loss of such benefit to the Company.

TERMS OF SERVICE

A. It shall be the Facility's responsibility to inform the Company of any change in its electric generation capability.

B. Any electric service delivered by the Company to the Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

C. A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

1. In the first year of operation, the security deposit shall be based upon the singular month in which the Facility's projected purchases from the Company exceed, by the greatest

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
First Revised Sheet No. 9.93
Canceling Original Sheet No. 9.93

PAGE	EFFECTIVE DATE
13 of 18	June 14, 2011

(Continued from Schedule REF-1, Sheet No. 9.92)

amount, the Company's estimated purchases from the Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon interconnection.

2. For each year thereafter, a review of the actual sales and purchases between the Facility and the Company shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Facility exceed the actual sales to the Company in that month.

D. The Company shall specify the point of interconnection and voltage level.

E. Facilities directly interconnected with the Company shall be required to sign the Company's filed Standard Interconnection Agreement in order to to engage in parallel operations with the Company. The Facility shall recognize that its generation equipment and other related infrastructure may have unique interconnection requirements which will be separately addressed by modifications to the Company's General Standards for Safety and Interconnection where applicable.

F. Facilities indirectly interconnected with the Company are required to make all arrangements needed to deliver the capacity and energy purchased from the Facility by the Company to the Company's interchange point with the delivering utility.

G. Service under this Schedule is subject to the rules and regulations of the Company and the FPSC as well as other applicable federal and state legislation or regulations.

SPECIAL PROVISIONS

A. Special contracts deviating from the above Schedule are allowable provided they are agreed to by the Company and approved by the FPSC.

B. A Facility directly interconnected with the Company may sell firm capacity and energy to a utility other than the Company. Where such agreements exist, the Company will provide transmission wheeling service to deliver the Facility's power to the purchasing utility or to an intermediate utility. In addition, the Company will provide transmission wheeling service through its territory for a Facility indirectly interconnected with the Company, for delivery of the Facility's power to the purchasing utility or to an intermediate utility. In either case, where existing Company transmission capacity exists, the Company will impose a charge for wheeling Facility capacity and energy, measured at the point of delivery to the Company.

The Facility shall be responsible for all costs associated with such wheeling including:

1. Wheeling charges;
2. Line losses incurred by the Company; and
3. Inadvertent energy flows resulting from such wheeling.

ISSUED BY: Mark Crosswhite

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Original Sheet No. 9.95

PAGE	EFFECTIVE DATE
15 OF 16	May 22, 2007

(Continued from Schedule REF-1, Sheet No. 9.94)

Depending on the nature of the Facility's operation, financial health and solvency, and its ability to meet the terms and conditions of the Company's Renewable Standard Offer Contract, one of the following, at the Company's discretion, may be used as an alternative to a cash deposit as a means of securing the completion of the Facility's project in accord with the executed Renewable Standard Offer Contract:

1. an unconditional, irrevocable direct pay letter; or
2. surety bond; or
3. other means acceptable to the Company.

The Company will cooperate with each Facility seeking an alternative to a cash security deposit as an acceptable means of securing the completion of the Facility's installation in accord with an executed Renewable Standard Offer Contract. The Company will endeavor in good faith to accommodate an equivalent to a cash security deposit which is in the best interests of both the Facility and the Company's customers.

In the case of a governmental solid waste Facility, pursuant to Subsection 366.91 (3), Florida Statutes and FPSC Rule 25-17.091, F.A.C., the following will be acceptable to the Company:

> The unsecured promise of a municipal, county, or state government that it will pay the actual damages incurred by the Company because the governmental Facility fails to come on line prior to the planned in-service date for the Avoided Unit or Resource.

D. Election of Early Capacity Payments under an Option other than (1) through (4) above, and/or election of the Fixed Energy Payments will result in the Company's immediate re-evaluation of the completion security requirements as addressed above in order to determine the adequacy of such security instruments. Given the terms and conditions ultimately set in the Renewable Standard Offer Contract, additional security requirements may be specified by the Company.

ISSUED BY: Susan Story

GULF POWER
A SOUTHERN COMPANY

Section No. IX
First Revised Sheet No. 9.94
Canceling Original Sheet No. 9.94

PAGE	EFFECTIVE DATE
14 of 16	[illegible]

(Continued from Schedule REF-1, Sheet No. 9.93)

Energy delivered to the Company shall be adjusted before delivery to another utility.

Interstate transactions are defined as those determined to be in the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Capacity delivered to the Company shall be adjusted before delivery to another utility. The following estimated adjustment factors are supplied for informational purposes only:

Renewable Facility Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	0.96758
Substation Voltage Delivery	0.94103
Primary Distribution Voltage Delivery	0.91001

All charges and adjustments for wheeling will be determined on a case-by-case basis.

Where wheeling power produced by a Facility for delivery to the Company or to another utility will impair the Company's ability to give adequate service to the rest of the Company's customers or place an undue burden on the Company, the Company may petition the FPSC for a waiver of this Special Provision B, or require the Facility to pay for the necessary transmission system improvements in accordance with the National Energy Policy Act of 1992, or other applicable Federal law.

In order to establish the appropriate transmission service arrangements, the Facility must contact:

Manager Transmission Services
Southern Company Services
Post Office Box 2625
Birmingham AL 35202

C. As a means of protecting the Company's customers from the possibility of a Facility not coming on line as provided for under an executed Renewable Standard Offer Contract and in order to provide the Company with additional and immediately available funds for its use to secure replacement and reserve power in the event that the Facility fails to successfully complete construction and come on line in accord with the executed Renewable Standard Offer Contract, the Company requires that a cash completion security deposit equal to $20 per kw of the nameplate capacity of the Facility's generator unit(s) at the time the Company's Renewable Standard Offer Contract is executed by the Facility. At the election of the Facility, the completion security deposit may be phased in such that one half of the total deposit due is paid at contract execution and the remainder within 12 months after contract execution.

ISSUED BY: Mark Crosswhite

GULF POWER
A SOUTHERN COMPANY

Section No. IX
First Revised Sheet No. 9.96
Canceling Original Sheet No. 9.96

PAGE	EFFECTIVE DATE
16 of 16	July 14, 2009

(Continued from Schedule REF-1, Sheet No. 9.95)

E. The Company, in evaluating the viability of any particular offer may exercise its rights under FPSC Rule 25-17.0832(4)(c)(2)(b), F.A.C.

F. In the event that the Facility decides to sell any or all Renewable Energy Certificates, Green Tags, or other tradable environmental interests (collectively "Environmental Interests") that result from the electric generation of the Facility during the term of an executed Renewable Standard Offer Contract, the Facility shall provide notice to the Company of its intent to sell such Environmental Interests and provide the Company a reasonable opportunity to offer to purchase such Environmental Interests.

G. All Renewable Standard Offer Contracts for the purchase of capacity and energy from a Facility shall include a provision to reopen the contract, at the election of either party, limited to changes affecting the Company's full avoided costs of the unit on which the Renewable Standard Offer Contract is based as a result of new environmental or other regulatory requirements enacted during the term of the contract.

ISSUED BY: Susan Story

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.97
Canceling Third Revised Sheet No. 9.97

STANDARD OFFER CONTRACT FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM A RENEWABLE ENERGY FACILITY OR SMALL QUALIFYING FACILITY
("RENEWABLE STANDARD OFFER CONTRACT")

PAGE	EFFECTIVE DATE
1 of 18	July 17, 2014

THIS AGREEMENT is made and entered into this _____ day of _____________, ______ by and between ____________________________, hereinafter referred to as the "Seller"; and Gulf Power Company, a corporation, hereinafter referred to as the "Company". The Seller and the Company shall collectively be referred to herein as the "Parties".

WITNESSETH:

WHEREAS, for purposes of this contract, the term "Renewable Energy Facility" means a facility that produces electrical energy from one or more of the sources stated in Florida Public Service Commission (FPSC) Rule 25-17.210 (1), Florida Administrative Code (F.A.C.), and the term "Small Qualifying Facility" means a facility with a design capacity of 100 KW or less as defined in FPSC Rule 25-17.080, F.A.C., thus, both "Renewable Energy Facility" and "Small Qualifying Facility" are herein referred to as "Facility"; and

WHEREAS, the Seller desires to sell, and the Company desires to purchase, firm capacity and energy to be generated by the Facility, such sale and purchase to be consistent with FPSC Rules 25-17.080 through 25-17.091; and

WHEREAS, the Seller, in accordance with FPSC Rule 25-17.087, F.A.C., has entered into an interconnection agreement with the utility that the Facility is directly interconnected, attached hereto as Appendix A; and

WHEREAS, the FPSC has approved the following standard contract for use in the acceptance of the Company's standard offer for the purchase of firm capacity and energy from Facilities.

NOW THEREFORE, for mutual consideration the Parties agree as follows:

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.98
Canceling First Revised Sheet No. 9.98

PAGE	EFFECTIVE DATE
2 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.97)

1. Facility

The Seller either contemplates installing and operating or has installed and is operating a Facility comprised in whole or in part of the following generator units located at ____:

Unit	Description (Type)	Initial In-Service Date	KVA Nameplate Rating	KW Output Rating	Fuel Source Primary	Fuel Source Secondary

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fifth Revised Sheet No. 9.99
Canceling Fourth Revised Sheet No. 9.99

PAGE	EFFECTIVE DATE
3 of 18	July 10, 201[illegible]

(Continued from Standard Offer Contract, Sheet No. 9.98)

The entire Facility, whether comprised in whole or in part of the generator units set forth above, is designed to produce a maximum of __________ kilowatts (KW) of electric power at an 85% power factor.

2. <u>Term of the Agreement</u>

This Agreement shall begin immediately upon its execution and the contemporaneous payment by the Seller to the Company of a completion security deposit in the amount of $20.00 times each KW of nameplate capacity of the Facility's generator unit(s). This Agreement shall end at 12:01 A.M., _______________, 20_____ (date specified shall be no earlier than May 31, 2033).

Notwithstanding the foregoing, if construction and commercial operation of the Facility are not accomplished before June 1, 2023, the Company's obligations to the Seller under this Agreement shall be considered to be of no force and effect. The Company shall be entitled to retain and use the funds required by the Company as a completion security deposit under this section of the Agreement.

At the election of the Seller, the completion security deposit may be phased in such that one half of the total deposit due is paid upon contract execution and the remainder is to be paid within 12 months after contract execution. If the Seller elects to phase in payment of the completion security deposit due under this paragraph, the effective date of the contract shall be the date of execution provided, however, that the Company shall have no further obligation to the Seller if either installment of the completion security deposit is not timely received by the Company.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.100
Canceling Third Revised Sheet No. 9.100

PAGE	EFFECTIVE DATE
4 of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.99)

Depending on the nature of the Facility's operation, financial health and solvency, and its ability to meet the terms and conditions of this Agreement, one of the following, at the Company's discretion in accordance with the provisions of Schedule REF-1, may be used as an alternative to a cash deposit as a means of securing the completion of the project in accord with this Agreement:

(a) an unconditional, irrevocable direct pay letter; or

(b) surety bond; or

(c) other means acceptable to the Company.

In the case of a governmental solid waste facility, pursuant to FPSC Rule 25-17.091, F.A.C., the following will be acceptable to the Company: the unsecured promise of a municipal, county, or state government to pay the actual damages incurred by the Company because the governmental facility fails to come on line prior to June 1, 2023.

The specific completion security vehicle agreed upon by the parties is: ________________

____

____

(IN ORDER FOR THIS FORM OF CONTRACT TO BE USED TO TENDER ACCEPTANCE OF THE COMPANY'S STANDARD OFFER BY A SELLER OTHER THAN A GOVERNMENTAL SOLID WASTE FACILITY, THE ABOVE LINE MUST SPECIFY CASH DEPOSIT IN THE APPROPRIATE AMOUNT UNLESS THE SELLER HAS SECURED THE PRIOR WRITTEN CONSENT FROM THE COMPANY TO AN ALTERNATIVE COMPLETION SECURITY VEHICLE.)

3. Sale of Electricity by the Facility

The Company agrees to purchase firm capacity and energy generated at the Facility and transmitted to the Company by the Facility. The purchase and sale of firm capacity and energy pursuant to this Agreement shall be in accordance with the following billing methodology (choose one):

( ) Net Billing Arrangement; or

( ) Simultaneous Purchase and Sales Arrangement.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.101
Canceling First Revised Sheet No. 9.101

PAGE	EFFECTIVE DATE
5 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.100)

The billing methodology chosen above may not be changed except in accordance with and subject to the following provisions of Rules 25-17.082 and 25-17.0832 F.A.C.:

(a) when a Facility selling as-available energy enters into a negotiated contract or standard offer contract for the sale of firm capacity and energy; or

(b) when a firm capacity and energy contract expires or is lawfully terminated by either the Facility or the purchasing utility; or

(c) when the Facility is selling as-available energy and has not changed billing methods within the last twelve months; and

(d) upon at least thirty days advance written notice to the Company;

(e) upon the installation of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Facility for such metering equipment and its installation;

(f) upon completion and approval of any alterations to the interconnection reasonably required to effect the change in billing an upon payment by the Facility for such alterations; and

(g) where the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or the tariff under which the Facility receives electrical service, or any previously agreed upon contractual provision between the Facility and the Company.

4. <u>Payment for Electricity Produced by the Facility</u>

4.1 <u>Energy</u>

The Company agrees to pay the Seller for energy the Facility produces and delivers for sale to the Company. The purchase and sale of energy pursuant to this Agreement shall be in accordance with the rates and procedures contained in Paragraph B of the **RATES FOR PURCHASES BY THE COMPANY** section of Schedule REF-1 as it exists at the time this Agreement is properly submitted by the Seller to the Company as tendered acceptance of the Company's Standard Offer.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.102
Canceling Third Revised Sheet No. 9.102

PAGE	EFFECTIVE DATE
[illegible] of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.101)

For all energy delivered by the Facility to the Company, the Seller elects to be paid pursuant to the method described in:

_____ Paragraph B (1), or

_____ Paragraph B (3)(b),

and (if applicable);

_____ Paragraph B (2), or

_____ Paragraph B (3)(a)

of the **RATES FOR PURCHASES BY THE COMPANY** section of Schedule REF-1. If the Seller elects any payment method under Paragraph B (3), the details underlying the derivation of the associated energy payments will be described in an exhibit to this Standard Offer Contract. The Company will provide the Seller an energy payment schedule for the elected payment method within thirty (30) days after receipt of a Seller's request for such information.

4.2 Capacity

4.2.1 Anticipated Committed Capacity. The Facility is expected to deliver approximately ______ kilowatts of capacity, beginning on or about _____________, 20_____. (Date specified may not be later than June 1, 2023.)

The Facility may finalize its Committed Capacity (CC) after initial facility testing, and specify when capacity payments are to begin, by completing Paragraph 4.2.2 at a date subsequent to the execution of this Agreement by the parties. However, the Seller must complete Paragraph 4.2.2 before June 1, 2023 in order to be entitled to any capacity payments pursuant to this Agreement. The final Committed Capacity set forth in Paragraph 4.2.2 shall not exceed plus or minus ten percent of the above estimate. The date specified in Paragraph 4.2.2 as the date on which capacity payments shall begin shall be no earlier than the date specified above, nor any later than June 1, 2023.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
~~Eighth~~Ninth Revised Sheet No. 9.103
Canceling ~~Seventh~~Eighth Revised Sheet No. 9.103

PAGE	EFFECTIVE DATE
7 of 18	[illegible]

(Continued from Standard Offer Contract, Sheet No. 9.102)

4.2.2 Actual Committed Capacity. The capacity committed by the Facility (Committed Capacity or CC) for the purposes of this Agreement is ______ kilowatts beginning ________________, _______. The Seller is committing this amount of capacity based on its agreement and commitment that this capacity will maintain an Equivalent Availability Factor (EAF) of 95%. The EAF will be based on the economic operation of a combustion turbine generating facility (Avoided Unit) that Gulf has designated as the Avoided Unit for purposes of the Standard Offer. The Seller elects to receive, and the Company agrees to commence calculating, capacity payments in accordance with this Agreement starting with the first billing month following the date specified in this paragraph as the date on which capacity sales under this Agreement will begin.

4.2.3 Capacity Payments. The Seller chooses to receive capacity payments from the Company under Option ________ or ________ a customized payment stream as described in the Company's Schedule REF-1 of the Company Tariff for Retail Electric Service as it exists at the time this Agreement is properly submitted by the Seller to the Company as tendered acceptance of the Company Standard Offer. If the customized payment option is chosen by the Seller as the preferred capacity payment option, the details underlying the derivation of such payment stream will be described in an exhibit to this Standard Offer Contract.

The Capacity Payments to be made by the Company to the Seller are based upon the Avoided Unit that the Company has designated for purposes of the Standard Offer. The Capacity Payments to the Seller are based on an avoided gas-fired Combustion Turbine generating facility with the following economic assumptions:

Size: ~~866~~654 MW total	Installed Costs (2023): ~~$608/kw~~$598/kW
Discount Rate: ~~6.72%~~6.34%	AFUDC Rate: ~~7.84%~~7.25%
Annual Inflation: ~~2.50%~~2.72%	K-factor: ~~1.3436~~1.3775
Annual Capacity Factor: ~~10.5%~~9.7%	Fixed O & M: ~~$14.17/kw-yr~~$14.42/kW-yr
Equivalent Availability: 95%	Unit Life: 40 years

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.104
Canceling Third Revised Sheet No. 9.104

PAGE	EFFECTIVE DATE
8 of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.103)

The Company agrees it will pay the Seller a capacity payment. This capacity payment will be the product of the Facility's Committed Capacity and the applicable rate from the Seller's chosen capacity payment option in accordance with the Company's Schedule REF-1, as it exists at the time this Agreement is properly submitted by the Seller to the Company as tendered acceptance of the Company's Standard Offer. In the event either: (1) the date specified in Section 2 of this Agreement is later than June 1, 2033; or (2) the date specified in Paragraph 4.2.2 as the date capacity payments are to begin is one other than the dates shown in Schedule REF-1, a payment schedule will be calculated by the Company and attached to this agreement as Exhibit D. Under those circumstances, the payment schedule set forth in Exhibit D will be used in the calculation of capacity payments pursuant to this paragraph. The Company will provide the Seller a capacity payment schedule for the chosen payment method within thirty (30) days after receipt of a Seller's request for such information. The capacity payment for a given month will be added to the energy payment for such month and tendered by the Company to the Seller as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

In October following each performance period, the Company will calculate the availability of the Facility over the most recent twelve month period ending August 31. For purposes of this Agreement, availability means Equivalent Availability Factor (EAF) as defined by the North American Electric Reliability Council Generating Availability Data System (NERC GADS) or its successor's indice. If the availability (EAF) of the Facility is not equal to or greater than 0.95 (95%), then the Seller will repay the Company a portion of the performance period capacity payments as calculated in accordance with the procedure detailed in the **ANNUAL CAPACITY AVAILABILITY FACTOR DETERMINATION** section of Rate Schedule REF-1.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.105
Canceling First Revised Sheet No. 9.105

PAGE	EFFECTIVE DATE
9 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.104)

Repayment under this paragraph shall not be construed as a limitation of the Company's right to pursue a claim against the Seller in any appropriate court or forum for the actual damages the Company incurs as a result of non-performance or default.

5. Metering Requirements

Hourly demand recording meters shall be required for each individual generator unit comprising a Facility with a total installed capacity of 100 kilowatts or more. Where the total installed capacity of the facility is less than 100 kilowatts, the Facility may select any one of the following options (choose one):

( ) hourly demand recording meter(s);
( ) dual kilowatt-hour register time-of-day meter(s); or
( ) standard kilowatt-hour meter(s).

Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

6. Electricity Production Schedule

During the term of this Agreement, the Seller agrees to:

(a) Adjust reactive power flow in the interconnection so as to remain within the range of 85% leading to 85% lagging power factor;

(b) Provide the Company, prior to October 1 of each calendar year (January through December), an estimate of the amount of firm capacity and energy to be generated by the Facility and delivered to the Company for each month of the following calendar year including the time, duration and magnitude of any planned outages or reductions in capacity;

(c) Promptly update the yearly generation schedule and maintenance schedule as and when any changes may be determined necessary;

(d) Coordinate its scheduled Facility outages with the Company;

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GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.106
Canceling Third Revised Sheet No. 9.106

PAGE	EFFECTIVE DATE
10 of 18	July 10, 2016

(Continued from Standard Offer Contract, Sheet No. 9.105)

(e) Comply with reasonable requirements of the Company regarding day-to-day or hour-by-hour communications between the parties relative to the performance of this Agreement; and

(f) Promptly notify the Company of the Facility's inability to supply any portion of its Committed Capacity. (Failure of the Seller to notify the Company of a known derating or inability to supply its full Committed Capacity from the Facility may, at the sole discretion of the Company, result in a determination of non-performance.)

7. <u>The Seller's Obligation if the Seller Receives Early Capacity Payments</u>

The Seller's payment option choice pursuant to paragraph 4.2.3 may result in payment by the Company for capacity delivered prior to June 1, 2023. The parties recognize that capacity payments received for any period through May 31, 2023, are in the nature of "early payment" for a future capacity benefit to the Company. To ensure that the Company will receive a capacity benefit for which early capacity payments have been made, or alternatively, that the Seller will repay the amount of early payments received to the extent the capacity benefit has not been conferred, the following provisions will apply:

The Company shall establish a Capacity Account. Amounts shall be added to the Capacity Account for each month through May 2023, in the amount of the Company's capacity payments made to the Seller pursuant to the Seller's chosen payment option from Schedule REF-1 or Exhibit D if applicable. The monthly balance in the Capacity Account shall accrue interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate is to be determined by the Company thirty days prior to the date of each payment or posting of interest to the account. Commencing on June 1, 2023, there shall be deducted from the Capacity Account an Early Payment Offset Amount to reduce the balance in the Capacity Account. Such Early Payment Offset Amount shall be equal to that amount which the Company would have paid for

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.107
Canceling Third Revised Sheet No. 9.107

PAGE	EFFECTIVE DATE
11 of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.106)

capacity in that month if the capacity payment had been calculated pursuant to Option 1 in Schedule REF-1 and the Seller had elected to begin receiving payment on June 1, 2023 minus the monthly capacity payment the Company makes to the Seller pursuant to the capacity payment option chosen by the Seller in paragraph 4.2.3.

The Seller shall owe the Company and be liable for the outstanding balance in the Capacity Account. The Company agrees to notify the Seller monthly as to the current Capacity Account balance. Prior to receipt of early capacity payments, the Seller shall execute a promise to repay any outstanding balance in the Capacity Account in the event of a default pursuant to this Agreement. Such promise shall be secured by means mutually acceptable to the Parties and in accordance with the provisions of Schedule REF-1.

The specific repayment assurance selected for purposes of this Agreement is:

____

____.

Any outstanding balance in the Capacity Account shall immediately become due and payable, in full, in the event of default or at the conclusion of the term of this Agreement. The Seller's obligation to pay the balance in the Capacity Account shall survive termination of this Agreement.

8. Non-Performance Provisions

The Seller shall be entitled to receive a complete refund of the security deposit described in Section 2 of this contract (or in the event an alternative completion security vehicle is in effect, release of that completion security) upon the Facility's achieving commercial in-service status (which, for purposes of this Agreement, shall include the demonstration of capability to perform by actual delivery of firm capacity and energy to the Company) provided that this occurs prior to June 1, 2023 and that said

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.108
Canceling Third Revised Sheet No. 9.108

PAGE	EFFECTIVE DATE
12 of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.107)

commercial in-service status is maintained from the date of initial demonstration to, through and including June 1, 2023. The Seller shall not be entitled to any of its security deposit if the Facility fails to achieve commercial in-service status prior to June 1, 2023 and maintain that status to, through and including said date. Additionally, once construction of the Facility or any additions necessary for the Facility to have the capability to deliver the anticipated Committed Capacity and energy to the Company from the Facility has commenced, the Seller will allow Company representatives to review quarterly the construction progress to provide the Company with a level of assurance that the Facility will be capable of delivering the anticipated Committed Capacity from the Facility on or before June 1, 2023.

Additionally, failure of the Seller to notify the Company of a known derating or inability to supply its full Committed Capacity from the Facility may, at the sole discretion of the Company, result in a determination of non-performance. Upon such determination by the Company, capacity payments to the Seller shall be suspended for a period of time equal to the time of the known derating or inability to supply the full Committed Capacity from the Facility or six months, whichever shall be longer.

9. Default

9.1 Mandatory Default. The Seller shall be in default under this Agreement if: (1) Seller either voluntarily declares bankruptcy or becomes subject to involuntary bankruptcy proceedings; or (2) the Facility ceases all electric generation for either of the Company's peak generation planning periods (summer or winter) occurring in a consecutive 12 month period. For purposes of this Agreement, the Company's summer peak generation planning period shall be May through September and the Company's winter peak generation planning period shall be December through February. The months included in the Company's peak generation planning periods may be changed, at the sole discretion of the Company, upon 12 months prior notice to the Seller.

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GULF POWER
A SOUTHERN COMPANY

Section No. IX
Fourth Revised Sheet No. 9.109
Canceling Third Revised Sheet No. 9.109

PAGE	EFFECTIVE DATE
13 of 18	July 10, 2014

(Continued from Standard Offer Contract, Sheet No. 9.108)

9.2 Optional Default. The Company may declare the Seller to be in default if: (1) at any time prior to June 1, 2023 and after capacity payments have begun, the Company has sufficient reason to believe that the Facility is unable to deliver its Committed Capacity; (2) because of a Seller's refusal, inability or anticipatory breach of its obligation to deliver its Committed Capacity after June 1, 2023; or (3) the Company has made three or more determinations of non-performance due to the failure of the Seller to notify the Company of a known derating or inability to supply Committed Capacity during any eighteen month period.

10. General Provisions

10.1 Permits. The Seller hereby agrees to obtain any and all governmental permits, certifications, or other authority the Seller and/or Facility are required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. The Company hereby agrees to obtain any and all governmental permits certifications or other authority the Company is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

10.2 Indemnification. The Seller agrees to indemnify and save harmless the Company, its subsidiaries or affiliates, and their respective employees, officers, and directors, against any and all liability, loss, damage, cost or expense which the Company, its subsidiaries, affiliates, and their respective employees, officers, and directors may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Seller in performing its obligations pursuant to this Agreement or the Seller's failure to abide by the provisions of this Agreement. The Company agrees to indemnify and save harmless the Seller against any and all liability, loss, damage, cost or expense which the Seller may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Company in performing its obligations pursuant to this Agreement or the Company's failure to abide by the provision of this Agreement. The Seller agrees to include the Company as an additional named insured in any liability insurance policy or policies the Seller obtains to protect the Seller's interests with respect to the Seller's indemnity and hold harmless assurances to parties contained in this Section.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.110
Canceling First Revised Sheet No. 9.110

PAGE	EFFECTIVE DATE
14 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.109)

The Seller shall deliver to the Company at least fifteen days prior to the delivery of any capacity and energy under this Agreement, a certificate of insurance certifying the Seller's and Facility's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida, protecting and indemnifying the Seller and the Company as an additional named insured, their officers, employees, and representatives, against all liability and expense on account of claims and suits for injuries or damages to persons or property arising out of the Seller's and the Facility's performance under or failure to abide by the terms of this Agreement, including without limitation any claims, damages or injuries caused by operation of any of the Facility's equipment or by the Seller's failure to maintain the Facility's equipment in satisfactory and safe operating conditions, or otherwise arising out of the performance by the Seller of the duties and obligations arising under the terms and conditions of this Agreement.

The policy providing such coverage shall provide comprehensive general liability insurance, including property damage, with limits in an amount not less than $1,000,000 for each occurrence. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify the Company within thirty days prior to the effective date of cancellation or a material change in the policy. The Seller shall pay all premiums and other charges required or due in order to maintain such coverage as required under this section in force during the entire period of this Agreement beginning with the initial delivery of capacity and energy to the Company.

10.3 <u>Taxes or Assessments</u>. It is the intent of the parties under this provision that the Seller hold the Company and its general body of ratepayers harmless from the effects of any additional taxes, assessments or other impositions that arise as a result of the purchase of energy or capacity from the Facility in lieu of other energy or capacity and that any savings in regards to taxes or assessments be included in the avoided cost payments made to the Seller to the extent

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GULF POWER
A SOUTHERN COMPANY

Section No. IX
Second Revised Sheet No. 9.111
Canceling First Revised Sheet No. 9.111

PAGE	EFFECTIVE DATE
15 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.110)

permitted by law. In the event the Company becomes liable for additional taxes, assessments or imposition arising out of its transaction with the Seller under either this agreement or any related interconnection agreement or due to changes in laws affecting the Company's purchases of energy or capacity from the Facility occurring after the execution of this agreement and for which the Company would not have been liable if it had produced the energy and/or constructed facilities sufficient to provide the capacity contemplated under this agreement itself, the Company may bill the Seller monthly for such additional expenses or may offset them against amounts due the Seller from the Company. Any savings in taxes, assessments or impositions that accrue to the Company as a result of its purchase of energy and capacity under this agreement that are not already reflected in the avoided energy or avoided capacity payments made to the Seller hereunder, shall be passed on to the Seller to the extent permitted by law without consequential penalty or loss of such benefit to the Company.

10.4 Force Majeure. If either party shall be unable, by reason of force majeure, to carry out its obligations under this Agreement, either wholly or in part, the party so failing shall give written notice and full particulars of such cause or causes to the other party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended during the continuance of such hindrance which, however, shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "force majeure" shall be taken to mean acts of God, strikes, lockouts or other industrial disturbances, wars, blockades, insurrections, riots, arrests and restraints of rules and people, environmental constraints lawfully imposed by federal, state or local government bodies, explosions, fires, floods, lightning, wind, perils of the sea provided, however, that no occurrences may be claimed to be a force majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the party attempting to make such claim. The Seller agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with the Company's system if the same are rendered inoperable

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GULF POWER
A SOUTHERN COMPANY

Section No. IX
Third Revised Sheet No. 9.112
Canceling Second Revised Sheet No. 9.112

PAGE	EFFECTIVE DATE
16 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.111)

due to actions of the Seller, its agents, or force majeure events affecting the Facility or the interconnection with the Company. The Company agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by the Company or its agents.

10.5 Assignment. The Seller shall have the right to assign its benefits under this Agreement, but the Seller shall not have the right to assign its obligations and duties without the Company's prior written approval.

10.6 Disclaimer. In executing this Agreement, the Company does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with the Seller or any assignee of this Agreement.

10.7 Notification. For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other party written instructions to contact another individual.

For Seller:
____
____
____
____
____

For Gulf Power Company:
Secretary and Treasurer
Gulf Power Company
One Energy Place
Pensacola FL 32520-0780

10.8 Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Florida.

10.9 Severability. If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a pubic authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Third Revised Sheet No. 9.113
Canceling Second Revised Sheet No. 9.113

PAGE	EFFECTIVE DATE
17 of 18	July 17, 2013

(Continued from Standard Offer Contract, Sheet No. 9.112)

10.10 Complete Agreement and Amendments. All previous communications or agreements between the parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement and, if required, approved by the FPSC.

10.11 Incorporation of Schedule. The parties agree that this Agreement shall be subject to all of the provisions contained in the Company's published Schedule REF-1 as approved and on file with the FPSC, as the Schedule exists at the time this Agreement is properly submitted by the Facility to the Company as tendered acceptance of the Company's standard offer.

10.12 Survival of Agreement. This Agreement, as may be amended from time to time, shall be binding and insure to the benefit of the Parties' respective successors-in-interest and legal representatives.

11. Environmental Interests

In the event that the Seller decides to sell any or all Renewable Energy Certificates, Green Tags, or other tradable environmental interests (collectively "Environmental Interests") that result from the electric generation of the Facility during the term of this Agreement, the Seller shall provide notice to the Company of its intent to sell such Environmental Interests and provide the Company a reasonable opportunity to offer to purchase such Environmental Interests.

12. Changes in Environmental and Governmental Regulations

This contract may be reopened at the election of either party in the event that environmental or other regulatory requirements are enacted during the term of this contract which either (a) increase or (b) decrease the full avoided costs of the Avoided Unit. The parties may negotiate a threshold amount of change below which this reopener will not apply.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IX
Third Revised Sheet No. 9.114
Canceling Second Revised Sheet No. 9.114

PAGE	EFFECTIVE DATE
18 of 18	July 17, 2014

(Continued from Standard Offer Contract, Sheet No. 9.113)

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their duly authorized officers.

GULF POWER COMPANY

By: ______________________________
(Signature)

____
(Print or Type Name)

Title: ______________________________

Date: ______________________________

SELLER

By: ______________________________
(Signature)

____
(Print or Type Name)

Title: ______________________________

Date: ______________________________

ISSUED BY: S. W. Connally, Jr.

Item 8

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

PoE

FROM: Division of Engineering (Lee) DL
Office of the General Counsel (Murphy) Matt for KY

RE: Docket No. 160073-EQ – Petition for approval of amended standard offer contract (Schedule COG-2), by Duke Energy Florida, LLC.

AGENDA: 06/09/16 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: Staff recommends the Commission simultaneously consider Docket Nos. 160069-EQ, 160072-EQ, and 160073-EQ.

Case Background

Section 366.91(3), Florida Statutes (F.S.), requires that each investor-owned utility (IOU) continuously offers to purchase capacity and energy from renewable generating facilities and small qualifying facilities. Florida Public Service Commission (Commission) Rules 25-17.200 through 25-17.310, Florida Administrative Code (F.A.C.), implement the statute and require each IOU to file with the Commission by April 1 of each year, a standard offer contract based on the next avoidable fossil fueled generating unit of each technology type identified in the utility's current Ten-Year Site Plan. On April 1, 2016, Duke Energy Florida, LLC. (DEF) filed a petition for approval of its standard offer contract based on its 2016 Ten-Year Site Plan. The Commission has jurisdiction over this standard offer contract pursuant to Sections 366.04 through 366.06 and 366.91, F.S.

Discussion of Issues

Issue 1: Should the Commission approve the revised standard offer contract and schedule COG-2 filed by Duke Energy Florida, LLC.?

Recommendation: Yes. The provisions of DEF's revised standard offer contract and schedule COG-2 conform to all requirements of Rules 25-17.200 through 25-17.310, F.A.C. DEF's revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation may select the payment stream best suited to its financial needs. (Lee)

Staff Analysis: Rule 25-17.250, F.A.C., requires that DEF, an IOU, continuously makes available a standard offer contract for the purchase of firm capacity and energy from renewable generating facilities (RF) and small qualifying facilities (QF) with design capacities of 100 kilowatts (kW) or less. Pursuant to Rule 25-17.250(1) and (3), F.A.C., the standard offer contract must provide a term of at least 10 years, and the payment terms must be based on the utility's next avoidable fossil-fueled generating unit identified in its most recent Ten-Year Site Plan or, if no avoided unit is identified, its next avoidable planned purchase.

DEF has identified an 849 megawatt (MW) natural gas-fueled combustion turbine (CT) facility as its next planned generating unit in its 2016 Ten-Year Site Plan. The projected in-service date of the unit is June 1, 2024.

The RF/QF operator may elect to make no commitment as to the quantity or timing of its deliveries to DEF, and to have a committed capacity of zero (0) MW. Under such a scenario, the energy is delivered on an as-available basis and the operator receives only an energy payment. Alternatively, the RF/QF operator may elect to commit to certain minimum performance requirements based on the identified avoided unit, such as being operational and delivering an agreed upon amount of capacity by the in-service date of the avoided unit, and thereby becomes eligible for capacity payments in addition to payments received for energy. The standard offer contract may also serve as a starting point for negotiation of contract terms by providing payment information to an RF/QF operator, in a situation where one or both parties desire particular contract terms other than those established in the standard offer.

In order to promote renewable generation, the Commission requires each IOU to offer multiple options for capacity payments, including the options to receive early or levelized payments. If the RF/QF operator elects to receive capacity payments under the normal or levelized contract options, it will receive as-available energy payments only until the in-service date of the avoided unit (in this case June 1, 2024), and thereafter begin receiving capacity payments in addition to the energy payments. If either the early or levelized option is selected, then the operator will begin receiving capacity payments earlier than the in-service date of the avoided unit. However, payments made under the early capacity payment options tend to be lower in the later years of the contract term because the net present value (NPV) of the total payments must remain equal for all contract payment options.

Table 1 below, estimates the annual payments for each payment option available under the revised standard offer contract to an operator with a 50 MW facility operating at a capacity factor of 95 percent, which is the minimum capacity factor required under the contract to qualify for full capacity payments. Normal and levelized capacity payments begin in 2024, reflecting the projected in-service date of the avoided unit (June 1, 2024).

Table 1 – Estimated Annual Payments to a 50 MW Renewable Facility (95% Capacity Factor)

Year	Energy Payment	Capacity Payment (By Type)			
		Normal	Levelized	Early	Early Levelized
	$(000)	$(000)	$(000)	$(000)	$(000)
2017	15,088	-	-	-	-
2018	15,560	-	-	-	-
2019	15,690	-	-	-	-
2020	16,384	-	-	-	-
2021	18,086	-	-	-	-
2022	20,049	-	-	2,185	2,510
2023	21,004	-	-	2,239	2,513
2024	21,877	1,688	1,917	2,295	2,517
2025	22,502	2,967	3,291	2,352	2,521
2026	23,457	3,041	3,296	2,411	2,525
2027	23,553	3,117	3,301	2,472	2,529
2028	24,388	3,195	3,306	2,533	2,533
2029	25,442	3,275	3,311	2,597	2,537
2030	25,801	3,356	3,317	2,662	2,542
2031	26,813	3,440	3,323	2,728	2,546
2032	27,531	3,526	3,328	2,796	2,551
2033	28,505	3,614	3,334	2,866	2,555
2034	29,647	3,705	3,340	2,938	2,560
2035	30,825	3,797	3,347	3,011	2,565
2036	31,837	3,892	3,353	3,087	2,570
Total	464,040	42,614	41,764	39,172	38,073
NPV (2017$)	235,340	17,211	17,211	17,211	17,211

DEF's revised tariff sheets of the standard offer contract, in type-and-strike format, are included as Attachment A to this recommendation. All of the changes made to DEF's tariff sheets are consistent with the updated avoided unit. Revisions include updates to the avoided unit, dates, and payment information which reflect the current economic and financial assumptions for the avoided unit costs. Other changes are primarily intended for clarification purposes.

Conclusion

The provisions of DEF's revised standard offer contract and schedule COG-2 conform to all requirements of Rules 25-17.200 through 25-17.310, F.A.C. DEF's revised standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation my select the payment stream best suited to its financial needs. Staff recommends that DEF's revised standard offer contract and related rate schedule be approved as filed.

Issue 2: Should this docket be closed?

Recommendation: Yes. This docket should be closed upon issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, DEF's standard offer contract may subsequently be revised. (Murphy)

Staff Analysis: This docket should be closed upon the issuance of a consummating order, unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the Commission's Proposed Agency Action Order. Potential signatories should be aware that, if a timely protest is filed, DEF's standard offer contract may subsequently be revised.

Standard Offer Contract (Schedule COG-2)

Duke Energy Florida, LLC.

Revisions in underline and strike-through format
shown the following sheets:

9.407, 9.410, 9.415, 9.419, 9.425, 9.427, 9.442, 9.445, 9.455, 9.457,
9.458, 9.467 and 9.468.

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY
AND ENERGY FROM A RENEWABLE ENERGY PRODUCER
OR QUALIFYING FACILITY LESS THAN 100 KW

TABLE OF CONTENTS

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A RENEWABLE ENERGY PRODUCER OR QUALIFYING FACILITY LESS THAN 100 KW

between

____

and

DUKE ENERGY FLORIDA

DUKE ENERGY.

APPENDIX D

TO

**DUKE ENERGY FLORIDA
RENEWABLE OR QUALIFYING FACILITY LESS THAN 100 KW
STANDARD OFFER CONTRACT**

RATE SCHEDULE COG-2

Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Renewable Energy Producer or a Qualifying Facility less than 100 kW.

SCHEDULE

COG-2, Firm Capacity and Energy from a Renewable Facility ("RF/QF") or a Qualifying Facility less than 100 kW ("QF")

AVAILABLE

DEF will, under the provisions of this schedule and the Contract to which this Appendix is attached and incorporated into by reference, purchase firm capacity and energy offered by a RF/QF as defined in the contract. DEF's obligation to contract to purchase firm capacity from such RF/QF by means of this schedule and the Contract will continue no later than the Expiration Date.

APPLICABLE

To RF/QFs as defined in the Contract producing capacity and energy for sale to DEF on a firm basis pursuant to the terms and conditions of this schedule and the Contract. "Firm Capacity and Energy" are described by FPSC Rule 25-17.0832, F.A.C., and are capacity and energy produced and sold by a RF/QF pursuant to the Contract provisions addressing (among other things) quantity, time and reliability of delivery.

CHARACTER OF SERVICE

Purchases within the territory served by DEF shall be, at the option of DEF, single or three phase, 60-hertz alternating current at any available standard DEF voltage. Purchases from outside the territory served by DEF shall be three phase, 60-hertz alternating current at the voltage level available at the interchange point between DEF and the entry delivering the Firm Capacity and Energy from the RF/QF.

DUKE ENERGY.

SECTION No. IX
FIRST REVISED SHEET NO. 9.453
CANCELS ORIGINAL SHEET NO. 9.453

LIMITATION

Purchases under this schedule are subject to FPSC Rules 25-17.080 through 25-17.310, F.A.C., and are limited to those RF/QFs which:

A. Are defined in the Contract;

B. Execute a Contract;

RATES FOR PURCHASES BY DEF

Firm Capacity and Energy are purchased at unit cost, in dollars per kilowatt per month and cents per kilowatt-hour, respectively, based on the value of deferring additional capacity required by DEF. For the purpose of this schedule, an Avoided Unit has been designated by DEF. DEF's next Avoided Unit has been identified in Section 4 of the Contract. Schedule 1 to this Appendix describes the methodology used to calculate payment schedules, general terms, and conditions applicable to the Contract filed and approved pursuant to FPSC Rules 25-17.080 through 25-17.310, F.A.C.

A. Firm Capacity Rates

Four options, A through D, as set forth below, are available for payments of firm capacity that is produced by a RF/QF and delivered to DEF. Once selected, an option shall remain in effect for the term of the Contract. Exemplary payment schedules, shown below, contain the monthly rate per kilowatt of firm Capacity which the RF/QF has contractually committed to deliver to DEF and are based on a contract term which extends through the Termination Date in Section 4 of the Contract. Payment schedules for other contract terms will be made available to any RF/QF upon request and may be calculated based on the methodologies described in Schedule 1. The currently approved parameters used to calculate the following schedule of payments are found in Schedule 2 to this Appendix.

Option A - Fixed Value of Deferral Payments - Normal Capacity

Payment schedules under this option are based on the value of a year-by-year deferral of DEF's Avoided Unit with an in-service date as of the Avoided Unit In-Service Date in Section 4 of the Contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Schedule 1. Once this option is selected, the current schedule of payments shall remain fixed and in effect throughout the term of the Contract. The payment schedule for this option follows in Table 3.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

Option B - Fixed Value of Deferral Payments - Early Capacity

Payment schedules under this option are based upon the early capital cost component of the value of a year-by-year deferral of the Avoided Unit. The term "early" with respect to Option B means that these payments can start prior to the anticipated in-service date of the Avoided Unit; provided, however, that under no circumstances may payments begin before this RF/QF is delivering Firm Capacity and Energy to DEF pursuant to the terms of the Contract. When this option is selected, the Capacity Payments shall be made monthly commencing no earlier than the Capacity Delivery Date of the RF/QF and calculated as shown on Schedule 1. Capacity Payments under Option B do not result in a prepayment or create a future benefit.

The RF/QF shall select the month and year in which the deliveries of firm capacity and energy to DEF are to commence and Capacity Payments are to start. DEF will provide the RF/QF with a schedule of capacity payment rates based on the month and year in which the deliveries of firm capacity and energy are to commence and the term of the Contract. The exemplary payment schedule in Table 3 is based on a contract term that begins on the Exemplary Early Capacity Payment Date in Section 4 of the Contract.

Option C - Fixed Value of Deferral Payment - Levelized Capacity

Payment schedules under this option are based upon the levelized capital cost component of the value of a year-by-year deferral of the Avoided Unit. The capital portion of Capacity Payments under this option shall consist of equal monthly payments over the term of the Contract, calculated as shown on Schedule 1. The fixed operation and maintenance portion of Capacity Payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expense associated with the Avoided Unit. These calculations are shown in Schedule 1. The payment schedule for this option is contained in Table 3. Capacity Payments under Option C do not result in a prepayment or create a future benefit.

Option D - Fixed Value of Deferral Payment - Early Levelized Capacity

Payment schedules under this option are based upon the early levelized capital cost component of the value of a year-by-year deferral of the Avoided Unit. The capital portion of Capacity Payments under this option shall consist of equal monthly payments over the term of the Contract, calculated as shown on Schedule 1. The fixed operation and maintenance expense shall be calculated as shown in Schedule 1.

The RF/QF shall select the month and year in which the deliveries of firm capacity and energy to DEF are to commence and Capacity Payments are to start. DEF will provide the RF/QF with a schedule of capacity payment rates based on the month and year in which the deliveries of firm capacity and energy are to commence and the term of the Contract. The exemplary payment schedule in Table 3 is based on a contract term that begins on the Exemplary Early Capacity Payment Date in Section 4 of the Contract.

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.455
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.455

TABLE 3
EXAMPLE MONTHLY CAPACITY PAYMENT IN $/kW/MONTH
DEF'S June 1, 2024 Undesignated CT
Renewable or Qualifying Facility Standard Offer Contract Avoided Capacity Payments

($/kW/MONTH)

Contract Year	Option A Normal Capacity Payment Starting on the Avoided Unit In-Service Date	Option B Early Capacity Payment Starting on the Exemplary Capacity Payment Date	Option C Levelized Capacity Payment Starting on the Avoided Unit In-Service Date	Option D Early Levelized Capacity Payment Starting on the Exemplary Capacity Payment Date
2021				
2022		~~3.57~~3.71		~~4.01~~4.19
2023		~~3.66~~3.80		~~4.02~~4.20
2024	~~4.64~~4.82	~~3.75~~3.90	~~5.12~~5.35	~~4.03~~4.20
2025	~~4.76~~4.94	~~3.84~~4.00	~~5.13~~5.36	~~4.04~~4.21
2026	~~4.87~~5.07	~~3.94~~4.10	~~5.15~~5.36	~~4.05~~4.22
2027	~~5.00~~5.19	~~4.04~~4.20	~~5.16~~5.37	~~4.06~~4.22
2028	~~5.12~~5.32	~~4.14~~4.30	~~5.17~~5.38	~~4.07~~4.23
2029	~~5.25~~5.46	~~4.24~~4.41	~~5.19~~5.39	~~4.08~~4.24
2030	~~5.38~~5.59	~~4.35~~4.52	~~5.20~~5.40	~~4.09~~4.24
2031	~~5.52~~5.73	~~4.46~~4.63	~~5.22~~5.41	~~4.10~~4.25
2032	~~5.65~~5.88	~~4.57~~4.75	~~5.23~~5.42	~~4.12~~4.26
2033	~~5.79~~6.02	~~4.68~~4.87	~~5.24~~5.43	~~4.13~~4.27
2034	~~5.94~~6.17	~~4.80~~4.99	~~5.26~~5.44	~~4.14~~4.28

1. The Capacity Payment schedules contained in this Contract assume a term of ten years from the Avoided Unit In-Service Date. In the event the RF/QF requests a term greater than ten years but less than the Avoided Unit Life then DEF shall prepare a schedule of Capacity Payments for the requested term. Such Capacity Payment rates shall be calculated utilizing the value-of-deferral methodology described in FPSC Rule 25-17.0832(6).

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

2. The RF/QF may also request an alternative Capacity Payment rate stream from DEF as authorized by Rule 25-17.250(4). Regardless of the Capacity Payment rate stream requested by the RF/QF, the cumulative present value of the capital cost payments made to the RF/QF over the term of the Contract shall not exceed the cumulative present value of the capital cost payments had such payments been made pursuant to FPSC Rule 25-17.0832(4)(g)(i). Fixed operation and maintenance expense shall be calculated to conform with FPSC Rule 25-17.0832(6)(b). Such an alternative Capacity Payment rate shall be subject to the Termination Fee in Appendix B.

   In the event that alternative Capacity Payment rates are agreed upon, such Capacity Payment rate schedule shall be attached to the Contract in Appendix E.

B. <u>Energy Rates</u>

<u>Payments Prior to the Avoided Unit In-Service Date</u>

1. The energy rate, in cents per kilowatt-hour (¢/kWh), shall be based on DEF's actual hourly avoided energy costs which are calculated by DEF in accordance with FPSC Rule 25-17.0825, F.A.C.

   The calculation of payments to the RF/QF shall be based on the sum over all hours of the billing period, of the product of each hour's avoided energy cost times the amount of energy (kWh) delivered to DEF from the Facility for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

2. Upon request of the RF/QF, DEF shall provide the RF/QF the option of receiving energy payments based on DEF's year-by-year projection of system incremental costs prior to hourly economy energy sales to other utilities, based on normal weather and fuel conditions plus a mutually agreed upon market volatility risk premium. If this option is chosen, such payments will be calculated on an annual basis and the first year's estimated payment schedule shall be attached to this Contract in Appendix E.

<u>Payments Starting on Avoided Unit In-Service Date</u>

The calculation of payments to the RF/QF for energy delivered to DEF on and after the Avoided Unit In-Service Date shall be the sum, over all hours of the Monthly Billing Period, of the product of (a) each hour's Firm Energy Rate (¢/kWh); and (b) the amount of energy (kWh) delivered to DEF from the Facility during that hour.

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.457
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.457

For any period during which energy is delivered by the RF/QF to DEF, the Firm Energy Rate in cents per kilowatt hour (¢/kWh) shall be the following on an hour-by-hour basis: the lesser of (a) the As-Available Energy Rate and (b) the Avoided Unit Energy Cost. The Avoided Unit Energy Cost, in cents per kilowatt - hour (¢/kWh) shall be defined as the product of (a) the Avoided Unit Fuel Cost and (b) the Avoided Unit Heat Rate; plus (c) the Avoided Unit Variable O&M.

For the purposes of this agreement, the Avoided Unit Fuel Cost shall be determined from gas price published in Platts Inside FERC, Gas Market Report, first of the month posting for Florida Gas Transmission ("FGT") Zone 3, plus other charges, surcharges and percentages that are in effect from time to time.

The Parties may mutually agree to fix a minority portion of the base energy payments associated with the Avoided Unit and amortize that fixed portion, on a present value basis, over the term of the Contract. Such fixed energy payments may, at the option of the RF/QF, start as early as the Avoided Unit In-Service Date. For purposes of this paragraph, "base energy payments associated with the Avoided Unit" means the energy costs of the Avoided Unit to the extent that the Avoided Unit would have been operated. If this option is mutually agreed upon, it will be attached to this Contract in Appendix E.

ESTIMATED AS-AVAILABLE ENERGY COST

For informational purposes only, the estimated incremental avoided energy costs for the next five years are as follows. The following estimates include variable operation and maintenance expenses.

Applicable Period	Average ¢/KWH	On-Peak ¢/KWH	Off-Peak ¢/KWH
2015	~~3.6~~3.5	~~3.9~~3.5	3.4
2016	3.6	~~3.8~~3.7	3.5
2017	3.7	3.8	~~3.5~~3.6
2018	~~3.8~~3.7	~~4.0~~3.8	3.6
2019	~~4.1~~3.9	~~4.4~~4.0	~~3.9~~3.8

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.458
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.458

ESTIMATED UNIT FUEL COST

The estimated unit fuel costs listed below are associated with the Avoided Unit and are based on current estimates of the price of natural gas.

$/MMBTU

~~2016~~2017	~~2017~~2018	~~2018~~2019	~~2019~~2020	~~2020~~2021	~~2021~~2022	~~2022~~2023	~~2023~~2024	~~2024~~2025
~~4.00~~3.41	~~4.11~~3.49	~~4.49~~3.84	~~5.15~~4.64	~~6.17~~5.34	~~6.40~~5.96	~~6.65~~6.19	~~6.91~~6.43	~~7.18~~6.67

DELIVERY VOLTAGE ADJUSTMENT

DEF's average system line losses are analyzed annually for the prior calendar year, and delivery efficiencies are developed for the transmission, distribution primary, and distribution secondary voltage levels. This analysis is provided in the DEF's Procedures For Changing The Real Power Loss Factor (currently Attachment Q) in its Open Access Transmission Tariff and DEF's fuel cost recovery filing with the FPSC. An adjustment factor, calculated as the reciprocal of the appropriate delivery efficiency factor, is applicable to the above determined energy costs if the RF/QF is within DEF's service territory to reflect the delivery voltage level at which RF/QF energy is received by the DEF.

The current delivery voltage adjustment factors are:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.~~0134~~0138
Primary Voltage Delivery	1.~~0234~~0238
Secondary Voltage Delivery	1.~~0536~~0533

PERFORMANCE CRITERIA

Payments for firm Capacity are conditioned on the RF/QF's ability to maintain the following performance criteria:

A. Capacity Delivery Date

The Capacity Delivery Date shall be no later than the Required Capacity Delivery Date.

B. Availability and Capacity Factor

The Facility's availability and capacity factor are used in the determination of firm Capacity Payments through a performance based calculation as detailed in Appendix A to the Contract.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

DUKE ENERGY.

SECTION No. IX
SECOND REVISED SHEET NO. 9.459
CANCELS FIRST REVISED SHEET NO. 9.459

METERING REQUIREMENTS

The RF/QFs within the territory served by DEF shall be required to purchase from DEF hourly recording meters to measure their energy deliveries to DEF. Energy purchases from the RF/QFs outside the territory of DEF shall be measured as the quantities scheduled for interchange to DEF by the entity delivering Firm Capacity and Energy to DEF.

For the purpose of this Contract, the on-peak hours shall be those hours occurring April 1 through October 31, from 11:00 a.m. to 10:00 p.m., and November 1 through March 31, from 6:00 a.m. to 12:00 noon and 5:00 p.m. to 10:00 p.m. prevailing Eastern time. DEF shall have the right to change such on-peak Hours by providing the RF/QF a minimum of thirty calendar days' advance written notice.

BILLING OPTIONS

A RF/QF, upon entering into this Contract for the sale of firm capacity and energy or prior to delivery of as-available energy, may elect to make either simultaneous purchases from and sales to DEF, or net sales to DEF; provided, however, that no such arrangement shall cause the RF/QF to sell more than the Facility's net output. A decision on billing methods may only be changed: 1) when a RF/QF selling as-available energy enters into this Contract for the sale of firm capacity and energy; 2) when a Contact expires or is lawfully terminated by either the RF/QF or DEF; 3) when the RF/QF is selling as-available energy and has not changed billing methods within the last twelve months; 4) when the election to change billing methods will not contravene the provisions of FPSC Rule 25-17.0832 or a contract between the RF/QF and DEF.

If a RF/QF elects to change billing methods, such changes shall be subject to the following: 1) upon at least thirty days advance written note to DEF; 2) the installation by DEF of any additional metering equipment reasonably required to effect the change in billing and upon payment by the RF/QF for such metering equipment and its installation; and 3) upon completion and approval by DEF of any alteration(s) to the interconnection reasonably required to effect the change in billing and upon payment by the RF/QF for such alteration(s).

Payments due a RF/QF will be made monthly and normally by the twentieth business day following the end of the billing period. The kilowatt-hours sold by the RF/QF and the applicable avoided energy rates at which payment are being made shall accompany the payment to the RF/QF.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
FOURTH REVISED SHEET NO. 9.460
CANCELS THIRD REVISED SHEET NO. 9.460

CHARGES TO RENEWABLE ENERGY PROVIDER

The RF/QF shall be responsible for all applicable charges as currently approved or as they may be approved by the Florida Public Service Commission, including, but not limited to:

A. Retail Service Charges

The RF/QF shall be responsible for all FPSC approved charges for any retail service that may be provided by DEF. The RF/QF shall be billed at the customer charge rate stated in DEF's applicable standby tariff monthly for the costs of meter reading, billing, and other administrative costs.

B. Interconnection Charges

Applicable Interconnection Charges are included in the transmission arrangements entered into with the Transmission Provider. Notwithstanding the above, Interconnection Charges must be in accordance with the provisions of FPSC Rule 25-17.087.

C. Transmission Charges

Applicable Transmission Charges are included in the transmission arrangements entered into with the Transmission Provider. Notwithstanding the above, Transmission Charges must be in accordance with the provisions of FPSC Rule 25-17.087.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
FIRST REVISED SHEET NO. 9.461
CANCELS ORIGINAL SHEET NO. 9.461

TERMS OF SERVICE

A. It shall be the RF/QF's responsibility to inform DEF of any change in its electric generation capability.

B. Any electric service delivered by DEF to a RF/QF located in DEF's service area shall be subject to the following terms and conditions:

(1) A RF/QF shall be metered separately and billed under the applicable retail rate schedule(s), whose terms and conditions shall pertain.

(2) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:

(i) In the first year of operation, the security deposit should be based upon the singular month in which the RF/QF's projected purchases from DEF exceed, by the greatest amount, DEF's estimated purchases from the RF/QF. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit is required upon interconnection.

(ii) For each year thereafter, a review of the actual sales and purchases between the RF/QF and DEF will be conducted to determine the actual month of maximum difference. The security deposit should be adjusted to equal twice the greatest amount by which the actual monthly purchases by the RF/QF exceed the actual sales in DEF in that month.

(3) DEF shall specify the point of interconnection and voltage level.

(4) The RF/QF must enter into an interconnection to DEF's system. Specific features of the RF/QF and its interconnection to DEF's facilities will be considered by DEF in preparing the interconnection agreement. Notwithstanding the above, interconnection with, and delivery into, the Company's system must be accomplished in accordance with the provisions of FPSC Rule 25-17.087.

C. Service under this rate schedule is subject to the rules and regulations of the FPSC.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SCHEDULE 1
TO RATE SCHEDULE COG-2

CALCULATION OF VALUE OF DEFERRAL PAYMENTS

APPLICABILITY

This Schedule 1 provides a detailed description of the methodology used by DEF to calculate the monthly values of deferring or avoiding the Avoided Unit identified in the Contract. When used in conjunction with the current FPSC-approved cost parameters associated with the Avoided Unit contained in Schedule 2, a RF/QF may determine the applicable value of deferral capacity payment rate associated with the timing and operation of its particular facility should the RF/QF enter into a Contract with DEF.

Also contained in this Schedule 1 is the discussion of the types and forms of surety bond requirements or equivalent assurance for payment of the Termination Fee acceptable to DEF in the event of contractual default by a RF/QF.

CALCULATION OF VALUE OF DEFERRAL OPTION A

FPSC Rule 25-17.0832(5) specifies that avoided capacity costs, in dollars per kilowatt per month, associated with capacity sold to a utility by a RF/QF pursuant to Contract shall be defined as the year-by-year value of deferral of the Avoided Unit. The year-by-year value of deferral shall be the difference in revenue requirements associated with deferring the Avoided Unit one year, and shall be calculated as follows:

$$VAC_m = 1/12\ [KI_n (1 - R) / (1 - R^L) + O_n]$$

Where, for a one year deferral:

VAC_m = utility's monthly value of avoided capacity, in dollars per kilowatt per month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present valued to the middle of the first year;

R = $(1 + i_p)/ (1 + r)$;

I_n = total direct and indirect cost, in mid-year dollars per kilowatt including AFUDC but excluding CWIP, of the Avoided Unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction for the Avoided Unit which would have been paid had the Avoided Unit been constructed;

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.468
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.468

FIXED VALUE OF DEFERRAL PAYMENTS - EARLY CAPACITY OPTION PARAMETERS

A_m	=	monthly avoided capital cost component of Capacity Payments to be made to the RF/QF starting as early as two years prior to the Avoided Unit In-Service Date, in dollars per kilowatt per month;	~~3.19~~3.51
i_p	=	annual escalation rate associated with the plant cost of the Avoided Unit;	2.50%
n	=	year for which early Capacity Payments to a RF/QF are to begin;	2022
F	=	the cumulative present value of the avoided capital cost component of Capacity Payments which would have been made had Capacity Payments commenced with the anticipated in-service date of the Avoided Unit and continued for a period of 10 years;	~~244.04~~304.22
r	=	annual discount rate, defined as DEF's incremental after-tax cost of capital;	6.~~95~~92%
t	=	the Term, in years, of the Contract for the purchase of firm capacity commencing prior to the in-service date of the Avoided Unit;	~~13~~14
G	=	the cumulative present value of the avoided fixed operation and maintenance expense component of Capacity Payments which would have been made had Capacity Payments commenced with the anticipated in-service date of the Avoided Unit and continued until the Termination Date.	~~28.93~~21.80

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

APPENDIX E

TO
DUKE ENERGY FLORIDA
RENEWABLE OR QUALIFYING FACILITY LESS THAN 100 KW
STANDARD OFFER CONTRACT

AGREED UPON PAYMENT SCHEDULES
AND OTHER MUTUAL AGREEMENTS

DUKE ENERGY.

SECTION No. IX
FIRST REVISED SHEET NO. 9.475
CANCELS ORIGINAL SHEET NO. 9.475

APPENDIX F
FPSC RULES 25-17.080 THROUGH 25-17.310
ARE PROVIDED IN SECTION VIII
ON THIS TARIFF BOOK

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION NO. IX
FOURTH REVISED SHEET NO.9.403
CANCELS THIRD REVISED SHEET NO. 9.403

TABLE OF CONTENTS

ii

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: July 10, 2014

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A RENEWABLE ENERGY PRODUCER OR QUALIFYING FACILITY LESS THAN 100 KW

THIS STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY (hereinafter referred to as the "Contract") is made and entered this ___ day of ________, _____ (hereinafter referred to as the "Execution Date"), by and between ____________________________ (hereinafter the Renewable Energy Provider/Qualifying Facility ("RF/QF"), and Duke Energy Florida, Inc. d/b/a Duke Energy (hereinafter "DEF"), a private utility corporation organized and existing under the laws of the State of Florida. The RF/QF and DEF shall be individually identified herein as the "Party" and collectively as the "Parties". This Contract contains five Appendices which are incorporated into and made part of this Contract: Appendix A: Monthly Capacity Payment Calculation; Appendix B: Termination Fee; Appendix C: Detailed Project Information; Appendix D: Rate Schedule COG-2; Appendix E: Agreed Upon Payment Schedules and Other Mutual Agreements; and Appendix F: Florida Public Service Commission ("FPSC") Rules 25-17.080 through 25-17.310, F.A.C.

WITNESSETH:

WHEREAS, the RF/QF desires to sell, and DEF desires to purchase electricity to be generated by the RF/QF consistent with Florida Statutes 366.91 (2006) and FPSC Rules 25-17.080 through 25-17.310 F.A.C.; and

WHEREAS, the RF/QF will acquire an interconnection/transmission service agreement with the utility in whose service territory the Facility is to be located, pursuant to which the RF/QF assumes contractual responsibility to make any and all transmission-related arrangements (including ancillary services) between the RF/QF and the Transmission Provider for delivery of the Facility's firm capacity and energy to DEF. The Parties recognize that the Transmission Provider may be DEF and that the transmission service will be provided under a separate agreement; and

WHEREAS, the FPSC has approved this Contract for the Purchase of Firm Capacity and Energy from a Renewable Energy Producer; and

WHEREAS, the RF/QF guarantees that the Facility is capable of delivering firm capacity and energy to DEF for the term of this Contract in a manner consistent with the provision of this Contract;

NOW, THEREFORE, for mutual consideration the Parties agree as follows:

DUKE ENERGY.

1. Definitions

"AFR" means the Facility's annual fuel requirement.

"AFTR" means the Facility's annual fuel transportation requirement

"Annual Capacity Billing Factor" or "ACBF" means 12 month rolling average of the Monthly Availability Factor as further defined and explained in Appendix A.

"Appendices" shall mean the schedules, exhibits, and attachments which are appended hereto and are hereby incorporated by reference and made a part of this Contract. Such Appendices include:

"Appendix A" sets forth the Monthly Capacity Payment Calculation.
"Appendix B" sets forth the Termination Fee.
"Appendix C" sets forth the Detailed Project Information.
"Appendix D" sets forth Rate Schedule COG-2.
"Appendix E" sets forth the Agreed Upon Payment Schedules and Other Mutual Agreements
"Appendix F" sets forth Florida Public Service Commission ("FPSC") Rules 25-17.080 through 25-17.310, F.A.C.

"As-Available Energy Rate" means the rate calculated by DEF in accordance with FPSC Rule 25-17.0825, F.A.C., and DEF's Rate Schedule COG-1, as they may each be amended from time to time

"Authorization to Construct" means authorization issued by any appropriate Government Agency to construct or reconstruct the Facility granted to RF/QF in accordance with the laws of the State of Florida and any relevant federal law.

"Avoided Unit" means the electrical generating unit described in Section 4 upon which this Contract is based.

"Avoided Unit Energy Cost" has the meaning assigned to it in Appendix D.

"Avoided Unit Fuel Cost" has the meaning assigned to it in Appendix D.

"Avoided Unit Heat Rate" means the average annual heat rate of the Avoided Unit as defined in Section 4.

"Avoided Unit In-Service Date" means the date upon which the Avoided Unit would have started commercial operation as specified in Section 4.

"Avoided Unit Life" means the economic life of the Avoided Unit.

"Avoided Unit Variable O&M" means the Avoided Unit variable operation and maintenance expenses as defined in Section 4. The annual escalation will begin in the payment for January deliveries.

"Base Capacity Payment" or "BCP" means capacity payment rates defined in Appendix D and further defined by the selection of Option A,B,C or D in Section 9.2 or in Appendix E if applicable.

"Base Year" means the year that this Contract was approved by the FPSC.

"Business Day" means any day except a day upon which banks licensed to operate in the State of Florida are authorized, directed or permitted to close, Saturday, Sunday or a weekday that is observed as a public holiday in the State of Florida.

"CAMD" means the Clean Air Markets Division of the Environmental Protection Agency or successor administrator (collectively with any local, state, regional, or federal entity given jurisdiction over a program involving transferability of Environmental Attributes).

"Capacity" means the minimum average hourly net capacity (generator output minus auxiliary load) measured over the Committed Capacity Test Period.

"Capacity Delivery Date" means the first calendar day immediately following the date of the Facility's successful completion of the first Committed Capacity Test.

"Capacity Payment" means the payment defined in Section 9.2 and Appendix A.

"Committed Capacity" or "CC" means the capacity in MW that the RF/QF commits to sell to DEF, the amount of which shall be determined in accordance with Section 7.

"Committed Capacity Test" means the testing of the capacity of the Facility performed in accordance with the procedures set forth in Section 8.

"Committed Capacity Test Period" means a test period of twenty-four (24) consecutive hours.

"Completed Permits Date" means the date by which the RF/QF must complete licensing and certification, and obtain all federal, state and local governmental, environmental, and licensing approvals required to initiate construction of the Facility including Qualifying Facility status. This date is specified in Section 4.

"Completion/Performance Security" means the security described in Section 11.

"Conditions Precedent" shall have the meaning assigned to it in Section 5.

"Contract" means this standard offer contract for the purchase of Firm Capacity and Energy from a Renewable Energy Producer or Qualifying Facility with a nameplate capacity of less than 100 kW.

"Credit Support Provider" means any Person that has provided an RF/QF Guarantee in connection with this Agreement.

DUKE ENERGY.

SECTION No. IX
~~THIRD~~ FOURTH REVISED SHEET NO. 9.407
CANCELS ~~SECOND~~ THIRD REVISED SHEET NO. 9.407

"Creditworthy" with respect to a Party or its Credit Support Provider, as applicable, means a party is rated at least BBB by Standard & Poor's (S&P), or at least Baa3 by Moody's Investor Services (Moody's). Rating shall be the unsecured, senior long-term debt rating, (not supported by third party credit enhancement) or the issuer rating will be used if not available. If a Party or its Credit Support Provider, as applicable, is rated by both S&P and Moody's, then the lower of the two ratings will apply.

"DEF" has the meaning assigned to it in the opening paragraph of this Contract.

"DEF Entities" has the meaning assigned to it in Section 16.

"Demonstration Period" means a sixty-hour period in which the Committed Capacity Test must be completed.

"Distribution System" means the distribution system consisting of electric lines, electric plant, transformers and switchgear used for conveying electricity to ultimate consumers, but not including any part of the Transmission System.

"Dispute" shall have the meaning assigned to it in Section 20.9.

"Drop Dead Date" means the date which is twelve (12) months following the Execution Date except for the condition defined in Section 5(a)(i). The Parties recognize that firm transmission service agreements can take up to 24 months to obtain so for Section 5(a)(i) only the Drop Dead Date means the date which is twenty four (24) months following the Execution Date..

"Eastern Prevailing Time" or "EPT" means the time in effect in the Eastern Time Zone of the Unites States of America, whether Eastern Standard Time or Eastern Daylight Savings Time.

"Effective Date" has the meaning assigned to it in Section 5.

"Electrical Interconnection Point" means the physical point at which the Facility is connected with the Transmission System or, if RF/QF interconnects with a Transmission System other than DEF's, DEF's interconnection with the Transmission Provider's Transmission System, or such other physical point on which RF/QF and DEF may agree.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

"Eligible Collateral" means (i) a Letter of Credit from a Qualified Institution or (ii) cash deposit provided to DEF by RF/QF or a combination of (i), and/or (ii) as outlined in Section 11.

"Energy" means megawatt-hours generated by the Facility of the character commonly known as three-phase, sixty hertz electric energy that is delivered at a nominal voltage at the Electrical Interconnection Point.

"Environmental Attributes" means all attributes of an environmental or other nature that are created or otherwise arise from the Facility's generation of electricity from a renewable energy source in contrast with the generation of electricity using nuclear or fossil fuels or other traditional resources. Forms of such attributes include, without limitation, any and all environmental air quality credits, green credits, renewable energy credits ("RECs"), carbon credits, emissions reduction credits, certificates, tags, offsets, allowances, or similar products or rights, howsoever entitled, (i) resulting from the avoidance of the emission of any gas, chemical, or other substance, including but not limited to, mercury, nitrogen oxide, sulfur dioxide, carbon dioxide, carbon monoxide, particulate matter or similar pollutants or contaminants of air, water or soil gas, chemical, or other substance, and (ii) attributable to the generation, purchase, sale or use of Energy from or by the Facility, or otherwise attributable to the Facility during the Term. Environmental Attributes include, without limitation, those currently existing or arising during the Term under local, state, regional, federal, or international legislation or regulation relevant to the avoidance of any emission described in this Contract under any governmental, regulatory or voluntary program, including, but not limited to, the United Nations Framework Convention on Climate Change and related Kyoto Protocol or other programs, laws or regulations involving or administered by the Clean Air Markets Division of the Environmental Protection Agency ("CAMD") or successor administrator (collectively with any local, state, regional, or federal entity given jurisdiction over a program involving transferability of Environmental Attributes,).

"Event of Default" has the meaning assigned to it in Section 14.

"Execution Date" has the meaning assigned to it in the opening paragraph of this Contract.

"Exemplary Early Capacity Payment Date" means the exemplary date used to calculate Capacity Payments for Option B and D. This date is specified in Section 4. The actual Capacity Payments for Option B and D will be calculated based upon the Required Capacity Delivery Date.

"Expiration Date" means the final date upon which this Contract can be executed. This date is specified in Section 4.

"Facility" means all equipment, as described in this Contract, used to produce electric energy and, and all equipment that is owned or controlled by the RF/QF required for parallel operation with the Transmission System. In the case of a cogenerator the Facility includes all equipment that is owned or controlled by the RF/QF to produce useful thermal energy through the sequential use of energy.

"Financial Closing" means the fulfillment of each of the following conditions:

(a) the execution and delivery of the Financing Documents; and

(b) all Conditions Precedent to the initial availability for disbursement of funds under the Financing Documents (other than relating to the effectiveness of this Contract) are satisfied or waived.

"Financing Documents" shall mean documentation with respect to any private equity investment in RF/QF, any loan agreements (including agreements for any subordinated debt), notes, bonds, indentures, guarantees, security agreements and hedging agreements relating to the financing or refinancing of the design, development, construction, Testing, Commissioning, operation and maintenance of the Facility or any guarantee by any Financing Party of the repayment of all or any portion of such financing or refinancing.

"Financing Party" means the Persons (including any trustee or agent on behalf of such Persons) providing financing or refinancing to or on behalf of RF/QF for the design, development, construction, testing, commissioning, operation and maintenance of the Facility (whether limited recourse, or with or without recourse).

"Firm Capacity and Energy" has the meaning assigned to it in Appendix D.

"Firm Capacity Rate" has the meaning assigned to it in Appendix D.

"Firm Energy Rate" has the meaning assigned to it in Appendix D.

"Force Majeure" has the meaning given to it in Section 18.

"FPSC" means the Florida Public Service Commission or its successor.

"Government Agency" means the United States of America, or any state or any other political subdivision thereof, including without limitation, any municipality, township or county, and any domestic entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government, including, without limitation, any corporation or other entity owned or controlled by any of the foregoing.

"IEEE" means the Institute of Electrical and Electronics Engineers, Inc.

"Indemnified Party" has the meaning assigned to it in Section 16.

"Indemnifying Party" has the meaning assigned to it in Section 16.

"Initial Reduction Value" has the meaning assigned to it in Appendix B.

"Insurance Services Office" has the meaning assigned to it in Section 17.

"KVA" means one or more kilovolts-amperes of electricity, as the context requires.

"kW" means one or more kilowatts of electricity, as the context requires.

"kWh" means one or more kilowatt-hours of electricity, as the context requires.

"Letter of Credit" means a stand-by letter of credit from a Qualified Institution that is acceptable to DEF whose approval may not be unreasonably withheld. The Letter of Credit must provide that DEF has the right to draw on the Letter of Credit in the event that less than twenty (20) Business Days remain until its expiration and RF/QF has failed to renew the Letter of Credit or provide replacement Eligible Collateral as required under this Agreement.

"LOI" means a letter of intent for fuel supply.

~~"Material Adverse Change" means any of the following events; (a) the RF/QF or its Credit Support Provider, if applicable, is no longer Creditworthy or (b) the RF/QF or its Credit Support Provider, if applicable. defaults on an aggregate of fifty million dollars ($50,000,000) or five percent (5%) of equity, whichever is less.~~

"MCPC" means the Monthly Capacity Payment for Option A.

"Monthly Billing Period" means the period beginning on the first calendar day of each calendar month, except that the initial Monthly Billing Period shall consist of the period beginning 12:01 a.m., on the Capacity Delivery Date and ending with the last calendar day of such month.

"Monthly Availability Factor" or "MAF" means the total energy received during the Monthly Billing Period for which the calculation is made, divided by the product of Committed Capacity and the total hours during the Monthly Billing Period.

"Monthly Capacity Payment" or "MCP" means the payment for Capacity calculated in accordance with Appendix A.

"MW" means one or more megawatts of electricity, as the context requires.

"MWh" means one or more megawatt-hours of electricity, as the context requires.

"Option A" means normal Capacity Payments as described in Appendix D.

"Option B" means early Capacity Payments as described in Appendix D.

"Option C" means levelized Capacity Payments as described in Appendix D.

"Option D" means early levelized Capacity Payments as described in Appendix D.

"Party" or "Parties" has the meaning assigned to it in the opening paragraph of this Contract.

"Person" means any individual, partnership, corporation, association, joint stock company trust, joint venture, unincorporated organization, or Governmental Agency (or any department, agency, or political subdivision thereof).

"Project Consents" mean the following Consents, each of which is necessary to RF/QF for the fulfillment of RF/QF's obligations hereunder:

(a) the Authorization to Construct;

(b) planning permission and consents in respect of the Facility, and any electricity substation located at the Facility site, including but not limited to, a prevention of significant deterioration permit, a noise, proximity and visual impact permit, and any required zoning permit; and

(c) any integrated pollution control license.

"Project Contracts" means this Contract, and any other contract required to construct, operate and maintain the Facility. The Project Contracts may include, but are not limited to, the turnkey engineering, procurement and construction contract, the electrical interconnection and operating agreement, the fuel supply agreement, the facility site lease, and the operation and maintenance agreement.

"Prudent Utility Practices" means any of the practices, methods, standards and acts (including, but not limited to, the practices, methods and acts engaged in or approved by a significant portion of owners and operators of power plants of technology, complexity and size similar to the Facility in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result and goals (including such goals as efficiency, reliability, economy and profitability) in a manner consistent with applicable facility design limits and equipment specifications and applicable laws and regulations. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of acceptable practices, methods or acts in each case taking into account the Facility as an independent power project.

"Qualifying Facility" or "QF" means a cogenerator, small power producer, or non-utility generator that has been certified or self-certified by the FERC as meeting certain ownership, operating and efficiency criteria established by the Federal Energy Regulatory Commission pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the criteria for which are currently set forth in 18 C.F.R. § 292, *et seq.* (2006), Section 210 of PURPA, 16 U.S.C. § 824a-3 (2005), 16 U.S.C. 796 *et seq.* (2006), and Section 1253 of EPAct 2005, Pub. L. No. 109-58, § 1253, 119 Stat. 594 (2005) or, alternatively, analogous provisions under the laws of the State of Florida.

"Qualified Institution" means the domestic office of a United States commercial bank or trust company or the United States branch of a foreign bank having total assets of at least ten billion dollars ($10,000,000,000) (which is not an affiliate of either party) and a general long-term senior unsecured debt rating of A- or higher (as rated by Standard & Poor's Ratings Group), or A3 or higher (as rated by Moody's Investor Services).

"Rate Schedule COG-1" means DEF's Agreement for Purchase of As-Available Energy and/or Parallel Operation with a Qualifying Facility as approved by the FPSC and as may be amended from time to time.

"REC" means renewable energy credits, green tags, green tickets, renewable certificates, tradable renewable energy credits ("T-REC") or any tradable certificate that is produced by a renewable generator in addition to and in proportion to the production of electrical energy.

"Reduction Value" has the meaning assigned to it in Appendix B.

"Renewable Facility" or "RF/QF" means an electrical generating unit or group of units at a single site, interconnected for synchronous operation and delivery of electricity to an electric utility, where the primary energy in British Thermal Units used for the production of electricity is from one or more of the following sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, hydroelectric power or waste heat from a commercial or industrial manufacturing process.

"Required Capacity Deliver Date" means the date specified in Appendix E. In the event that no Required Capacity Delivery Date is specified in Appendix E then the RF/QF shall achieve the Capacity Delivery Date on or before the Avoided Unit In-Service Date

"RF/QF Entities" has the meaning assigned to it in Section 16.

DUKE ENERGY.

SECTION NO. IX
SECOND REVISED SHEET NO.9.402
CANCELS FIRST REVISED SHEET NO. 9.402

TABLE OF CONTENTS
i

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

"RF/QF Insurance" has the meaning assigned to it in Section 17.

"RF/QF Performance Security" has the meaning assigned in Section 11.

"Security Documentation" has the meaning assigned to it in Section 12.

"Term" has the meaning assigned to it in Section 3.

"Termination Date" means the date upon which this Contract terminates unless terminated earlier in accordance with the provisions hereof. This date is specified in Section 4.

"Termination Fee" means the fee described in Appendix B as it applies to any Capacity Payments made under Option B, C or D.

"Termination Security" has the meaning assigned to it in Section 12.

"Transmission Provider" means the operator(s) of the Transmission System(s) or any successor thereof or any other entity or entities authorized to transmit Energy on behalf of RF/QF from the Electrical Interconnection Point.

"Transmission System" means the system of electric lines comprised wholly or substantially of high voltage lines, associated system protection, system stabilization, voltage transformation, and capacitance, reactance and other electric plant used for conveying electricity from a generating station to a substation, from one generating station to another, from one substation to another, or to or from any Electrical Interconnection Point or to ultimate consumers and shall include any interconnection owned by the Transmission Provider or DEF, but shall in no event include any lines which the Transmission Provider has specified to be part of the Distribution System except for any distribution facilities required to accept capacity and energy from the Facility.

2. Facility; Renewable Facility or Qualifying Facility Status

The Facility's location and generation capabilities are as described in Table 1 below.

TABLE 1

TECHNOLOGY AND GENERATOR CAPABILITIES	
Location: Specific legal description (e.g., metes and bounds or other legal description with street address required)	City: County:
Generator Type (Induction or Synchronous)	
Technology	
Fuel Type and Source	
Generator Rating (KVA)	
Maximum Capability (kW)	
Net Output (kW)	
Power Factor (%)	
Operating Voltage (kV)	
Peak Internal Load kW	

The RF/QF's failure to complete Table 1 in its entirety shall render this Contract null and void and of no further effect.

The RF/QF shall use the same fuel or energy source and maintain the status as a Renewable Facility or a Qualifying Facility throughout the term of this Contract. RF/QF shall at all times keep DEF informed of any material changes in its business which affects its Renewable Facility or Qualifying Facility status. DEF and RF/QF shall have the right, upon reasonable notice of not less than seven (7) Business Days, to inspect the Facility and to examine any books, records, or other documents reasonably deemed necessary to verify compliance with this Contract. In the event of an emergency at or in proximity to the RF/QF site that impacts DEF's system, DEF shall make reasonable efforts to contact the Facility and make arrangements for an emergency inspection. On or before March 31 of each year during the term of this Contract, the RF/QF shall provide to DEF a certificate signed by an officer of the RF/QF certifying that the RF/QF continuously maintained its status as a Renewable Facility or a Qualifying Facility during the prior calendar year.

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.415
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.415

3. Term of Contract

Except as otherwise provided herein, this Contract shall become effective immediately upon its execution by the Parties and shall end at 12:01 a.m. on the Termination Date, (the "Term") unless terminated earlier in accordance with the provisions hereof. Notwithstanding the foregoing, if the Capacity Delivery Date of the Facility is not accomplished by the RF/QF before the Required Capacity Delivery Date (or such later date as may be permitted by DEF pursuant to Section 7), this Contract shall be rendered null and void and DEF's shall have no obligations under this Contract.

4. Minimum Specifications and Milestones

As required by FPSC Rule 25-17.0832(4)(e), the minimum specifications pertaining to this Contract and milestone dates are as follows:

Avoided Unit	Undesignated Combustion Turbine
Avoided Unit Capacity	~~811~~ 849 MW
Avoided Unit In-Service Date	June 1, 2024
Avoided Unit Heat Rate	10,~~399~~ 239 BTU/kWh
Avoided Unit Variable O&M	0.~~0919~~1152¢ per kWh in mid-~~2015~~ 2016 dollars escalating annually at 2.50%
Avoided Unit Life	35 years
Capacity Payments begin	Avoided Unit In-Service Date unless Option B, or D is selected or amended in Appendix E
Termination Date	May 31, 2034 (10 years) unless amended in Appendix E
Minimum Performance Standards – On Peak Availability Factor*	~~94~~95%
Minimum Performance Standards – Off Peak Availability Factor	~~94~~95%
Minimum Availability Factor Required to qualify for a Capacity payment	~~74~~75%
Expiration Date	April 1, ~~2016~~2017
Completed Permits Date	June 1, ~~2021~~2022
Exemplary Early Capacity Payment Date	January 1, ~~2022~~2023

* RF/QF performance shall be as measured and/or described in Appendix A.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

5. Conditions Precedent

(a) Unless otherwise waived in writing by DEF, on or before the Drop Dead Date, RF/QF shall satisfy the following Conditions Precedent:

(i) RF/QF shall have obtained firm transmission service necessary to deliver Capacity and energy from the Facility to the Electrical Interconnection Point, in a form and substance satisfactory to RF/QF in its sole discretion;

(ii) RF/QF shall have obtained the Project Consents and any other Consents for which it is responsible under the terms hereof in a form and substance satisfactory to RF/QF in its sole discretion;

(iii) RF/QF shall have entered into Financing Documents relative to the construction of the Facility and have achieved Financial Closing in a form and substance satisfactory to RF/QF in its sole discretion;

(iv) RF/QF shall have entered into the Project Contracts in a form and substance satisfactory to RF/QF in its sole discretion;

(v) RF/QF shall have obtained insurance policies or coverage in compliance with Section 17;

(vi) Each Party shall have delivered to the other Party (i) a copy of its constitutional documents (certified by its corporate secretary as true, complete and up-to-date) and (ii) a copy of a corporate resolution approving the terms of this Contract and the transactions contemplated hereby and authorizing one or more individuals to execute this Contract on its behalf (such copy to have been certified by its corporate representative as true, complete and up-to-date);

(vii) RF/QF shall have obtained Qualifying Facility status from either the FPSC or FERC.

(b) Promptly upon satisfaction of the Conditions Precedent to be satisfied, the Party having satisfied the same shall deliver to the other Party a certificate evidencing such satisfaction. DEF may waive the satisfaction of a Condition Precedent at its sole discretion. Such waiver must be made in writing. Subject to there being no Event of Default which has occurred and/or is continuing as of the date upon which the last of such certificates is delivered, the date of such last certificate shall constitute the effective date of this Contract (the "Effective Date").

(c) Unless all Conditions Precedent are satisfied on or before the Drop Dead Date or such Conditions Precedent are waived in writing , this Contract shall terminate on such date and neither Party shall have any further liability to the other Party hereunder.

(d) RF/QF shall achieve the Capacity Delivery Date on or before the Required Capacity Delivery Date.

(e) RF/QF shall ensure that before the initial Committed Capacity Test:

(a) the Facility shall have been constructed so that the Committed Capacity Test may be duly and properly undertaken in accordance with Section 7; and

(b) an operable physical connection from the Facility to the Transmission System shall have been effected in accordance with the electrical interconnection and operating agreement required by the Transmission Provider, provided, however, that such physical connection shall be made consistent with the terms hereof.

6. Sale of Electricity by the RF/QF

6.1 Consistent with the terms hereof, the RF/QF shall sell to DEF and DEF shall purchase from the RF/QF electric power generated by the Facility. The purchase and sale of electricity pursuant to this Contract shall be a ( ) net billing arrangement or ( ) simultaneous purchase and sale arrangement; provided, however, that no such arrangement shall cause the RF/QF to sell more than the Facility's net output. The billing methodology may be changed at the option of the RF/QF, subject to the provisions of Appendix D.

6.2 Ownership and Offering For Sale Of Renewable Energy Attributes

The RF/QF shall retain any and all rights to own and to sell any and all Environmental Attributes associated with the electric generation of the Facility.

6.3 The RF/QF shall not rely on interruptible or curtailable standby service for the start up requirements (initial or otherwise) of the Facility.

6.4 The RF/QF shall be responsible for the scheduling of required transmission and for all costs, expenses, taxes, fees and charges associated with the delivery of energy to DEF. The RF/QF shall enter into a transmission service agreement with the Transmission Provider in whose service territory the Facility is to be located and the RF/QF shall make any and all transmission-related arrangements (including interconnection and ancillary services) between the RF/QF and the Transmission Provider for delivery of the Facility's firm Capacity and energy to DEF. The Capacity and energy amounts paid to the RF/QF hereunder do not include transmission losses. The RF/QF shall be responsible for transmission losses that occur prior to the point at which the RF/QF's energy is delivered to DEF. The Parties recognize that the Transmission Provider may be DEF and that if DEF is the Transmission Provider, the transmission service will be provided under a separate agreement.

7. Committed Capacity/Capacity Delivery Date

7.1 In the event that the RF/QF elects to make no commitment as to the quantity or timing of its deliveries to DEF, then its Committed Capacity as defined in the following Section 7.2 shall be zero (0) MW. If the Committed Capacity is zero (0) MW, Sections 7.2 though Section 7.7 and all of Section 8 shall not apply.

7.2 If the RF/QF commits to sell capacity to DEF, the amount of which shall be determined in accordance with this Section 7. Subject to Section 7.4, the Committed Capacity is set at ______ kW, with an expected Capacity Delivery Date on or before the Required Capacity Delivery Date.

7.3 Capacity testing of the Facility (each such test a Committed Capacity Test) shall be performed in accordance with the procedures set forth in Section 8. The Demonstration Period for the first Committed Capacity Test shall commence no earlier than ninety (90) days before the Required Capacity Delivery Date and testing must be completed before the Avoided Unit In-Service Date or an earlier date in Appendix E. The first Committed Capacity Test shall not be successfully completed unless the Facility demonstrates a Capacity of at least one hundred percent (100%) of the Committed Capacity set forth in Section 7.2. Subject to Section 8.1, the RF/QF may schedule and perform up to three (3) Committed Capacity Tests to satisfy the requirements of the Contract with respect to the first Committed Capacity Test.

7.4 In addition to the first Committed Capacity Test, DEF shall have the right to require the RF/QF, after notice of no less than ten (10) Business Days prior to such proposed event, to validate the Committed Capacity by means of a Committed Capacity Test at any time, up to two (2) times per year, the results of which shall be provided to DEF within seven (7) calendar days of the conclusion of such test. On and after the date of such requested Committed Capacity Test, and until the completion of a subsequent Committed Capacity Test, the Committed Capacity shall be set at the lower of the Capacity tested or the Committed Capacity as set forth in Section 7.2. Provided however, any such second test requested within a twelve (12) month period must be for cause.

7.5 Notwithstanding anything contrary to the terms hereof, the Committed Capacity may not exceed the amount set forth in Section 7.2 without the consent of DEF, which consent shall be granted in DEF's sole discretion.

7.6 Unless Option B or D as contained in Appendix D or Appendix E is chosen by RF/QF, DEF shall make no Capacity Payments to the RF/QF prior to the Avoided Unit In-Service Date.

7.7 The RF/QF shall be entitled to receive Capacity Payments beginning on the Capacity Delivery Date, provided the Capacity Delivery Date occurs before the Required Capacity Delivery Date (or such later date permitted by DEF). If the Capacity Delivery Date does not occur before the Required Capacity Delivery Date, DEF shall immediately be entitled to draw down the Completion/Performance Security in full.

8. **Testing Procedures**

8.1 The Committed Capacity Test must be completed successfully within the Demonstration Period, which period, including the approximate start time of the Committed Capacity Test, shall be selected and scheduled by the RF/QF by means of a written notice to DEF delivered at least thirty (30) calendar days prior to the start of such period. The provisions of the foregoing sentence shall not apply to any Committed Capacity Test ordered by DEF under any of the provisions of this Contract. DEF shall have the right to be present onsite to monitor firsthand any Committed Capacity Test required or permitted under this Contract.

8.2 The Committed Capacity Test results shall be based on a test period of twenty-four (24) consecutive hours (the "Committed Capacity Test Period") at the highest sustained net kW rating at which the Facility can operate without exceeding the design operating conditions, temperature, pressures, and other parameters defined by the applicable manufacturer(s) for steady state operations at the Facility. The Committed Capacity Test Period shall commence at the time designated by the RF/QF pursuant to Section 8.1 or at such time requested by DEF pursuant to Section 7.4; provided, however, that the Committed Capacity Test Period may commence earlier than such time in the event that DEF is notified of, and consents to, such earlier time.

8.3 Normal station service use of unit auxiliaries, including, without limitation, cooling towers, heat exchangers, and other equipment required by law, shall be in service during the Committed Capacity Test Period.

8.4 The Capacity of the Facility shall be the minimum ~~average~~ hourly net output in kW (generator output minus auxiliary) measured over the Committed Capacity Test Period.

8.5 The Committed Capacity Test shall be performed according to standard industry testing procedures for the appropriate technology of the RF/QF.

8.6 The results of any Committed Capacity Test, including all data related to Facility operation and performance during testing, shall be submitted to DEF by the RF/QF within seven (7) calendar days of the conclusion of the Committed Capacity Test. The RF/QF shall certify that all such data is accurate and complete.

9. Payment for Electricity Produced by the Facility

9.1 Energy

9.1.1 DEF agrees to pay the RF/QF for energy produced by the Facility and delivered to DEF in accordance with the rates and procedures contained in DEF's approved Rate Schedule COG-1, as it may be amended from time to time if the Committed Capacity pursuant to Section 7.2 is set to zero. If the Committed Capacity is greater than zero MW, then DEF agrees to pay the RF/QF for energy produced by the Facility and delivered to DEF in accordance with the rates and procedures contained in Appendix D, as it may be amended from time to time. The Parties agree that this Contract shall be subject to all of the provisions contained in Rate Schedule COG-1 or Appendix D whichever applies as approved and on file with the FPSC.

9.1.2 DEF may, at its option, limit deliveries under this Contract to 110% of the Committed Capacity as set forth in Section 7. In the event that DEF chooses to limit deliveries, any energy in excess of 110% of the Committed Capacity will be paid for at the rates defined in Rate Schedule COG-1 and shall not be included in the calculations in Appendix A hereto.

9.2 Capacity

DEF agrees to pay the RF/QF for the Capacity described in Section 7 in accordance with the rates and procedures contained in Appendix D, as it may be amended and approved from time to time by the FPSC, and pursuant to the election of Option __________ of Appendix D or an alternative rate schedule in Appendix E. The RF/QF understands and agrees that Capacity Payments will only be made if the Capacity Delivery Date occurs before the Required Capacity Delivery Date and the Facility is delivering firm Capacity and Energy to DEF. Once so selected, this Option, the Firm Capacity Rate and/or the Firm Energy Rate cannot be changed for the term of this Contract.

9.3 Payments for Energy and Capacity

9.3.1 Payments due the RF/QF will be made monthly, and normally by the twentieth Business Day following the end of the billing period. The kilowatt-hours sold by the RF/QF and the applicable avoided energy rate at which payments are being made shall accompany the payment to the RF/QF.

9.3.2 Payments to be made under this Contract shall, for a period of not longer than two (2) years, remain subject to adjustment based on billing adjustments due to error or omission by either Party, provided that such adjustments have been agreed to between the Parties.

10. Electricity Production and Plant Maintenance Schedule

10.1 No later than sixty (60) calendar days prior to the Required Capacity Delivery Date, and prior to October 1 of each calendar year thereafter during the term of this Contract, the RF/QF shall submit to DEF in writing a good-faith estimate of the amount of electricity to be generated by the Facility and delivered to DEF for each month of the following calendar year, including the time, duration and magnitude of any scheduled maintenance period(s) or reductions in Capacity. The RF/QF agrees to provide updates to its planned maintenance periods as they become known. The Parties agree to discuss coordinating scheduled maintenance schedules.

10.2 By October 31 of each calendar year, DEF shall notify the RF/QF in writing whether the requested scheduled maintenance periods in the detailed plan are acceptable. If DEF does not accept any of the requested scheduled maintenance periods, DEF shall advise the RF/QF of the time period closest to the requested period(s) when the outage(s) can be scheduled. The RF/QF shall only schedule outages during periods approved by DEF, and such approval shall not be unreasonably withheld. Once the schedule for the detailed plan has been established and approved, either Party requesting a subsequent change in such schedule, except when such change is due to Force Majeure, must obtain approval for such change from the other Party. Such approval shall not be unreasonably withheld or delayed. Scheduled maintenance outage days shall be limited to twenty four days per calendar year. In no event shall maintenance periods be scheduled during the following periods: June 1 through September 15 and December 1 through and including the last day of February.

10.3 The RF/QF shall comply with reasonable requests by DEF regarding day-to-day and hour-by-hour communication between the Parties relative to electricity production and maintenance scheduling.

10.4 The Parties recognize that the intent of the availability factor in Section 4 of this Contract includes an allowance for scheduled outages, forced outages and forced reductions in the output of the Facility. Therefore, the RF/QF shall provide DEF with notification of any forced outage or reduction in output which shall include the time and date at which the forced outage or reduction occurred, a brief description of the cause of the outage or reduction and the time and date when the forced outage or reduction ceased and the Facility was able to return to normal operation. This notice shall be provided to DEF within seventy-two (72) hours of the end of the forced outage or reduction.

The RF/QF is required to provide the total electrical output to DEF except (i) during a period that was scheduled in Section 10.2, (ii) during a period in which notification of a forced outage or reduction was provided, (iii) during an event of Force Majeure or (iv) during a curtailment period as described in Section 10.5.5. In no event shall the RF/QF deliver any portion of their electrical output to a third party.

10.5 Dispatch and Control

10.5.1 Power supplied by the RF/QF hereunder shall be in the form of three-phase 60 hertz alternating current, at a nominal operating voltage of ______ volts (______ kV) and power factor dispatchable and controllable in the range of 90% lagging to 90% leading as measured at the interconnection point to maintain system operating parameters, including power factor, as specified from time to time by DEF.

10.5.2 The RF/QF shall operate the Facility with all system protective equipment in service whenever the Facility is connected to, or is operated in parallel with, DEF's system, except for normal testing and repair in accordance with good engineering and operating practices as agreed by the Parties. The RF/QF shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. All RF/QF facilities shall meet IEEE and utility standards. The RF/QF shall have independent, third party qualified personnel test, calibrate and certify in writing all protective equipment at least once every twelve (12) months in accordance with good engineering and operating practices. A unit functional trip test shall be performed after each overhaul of the Facility's turbine, generator or boilers and results provided to DEF in writing prior to returning the equipment to service. The specifics of the unit functional trip test will be consistent with Prudent Utility Practices.

10.5.3 If the Facility is separated from the DEF system for any reason, under no circumstances shall the RF/QF reconnect the Facility to DEF's system without first obtaining DEF'S specific approval.

10.5.4 During the term of this Contract, the RF/QF shall employ qualified personnel for managing, operating and maintaining the Facility and for coordinating such with DEF. The RF/QF shall ensure that operating personnel are on duty at all times, twenty-four (24) hours a calendar day and seven (7) calendar days a week. Additionally, during the term of this Contract, the RF/QF shall operate and maintain the Facility in such a manner as to ensure compliance with its obligations hereunder and in accordance with applicable law and Prudent Utility Practices.

10.5.5 DEF shall not be obligated to purchase, and may require curtailed or reduced deliveries of energy to the extent allowed under FPSC Rule 25-17.086 and under any curtailment plan which DEF may have on file with the FPSC from time to time.

10.5.6 During the term of this Contract, the RF/QF shall maintain sufficient fuel on the site of the Facility to deliver the capacity and energy associated with the Committed Capacity for an uninterrupted seventy-two-(72) hour period. At DEF's request, the RF/QF shall demonstrate this capability to DEF's reasonable satisfaction. During the term of this Contract, the RF/QF's output shall remain within a band of plus or minus ten percent (10%) of the daily output level or levels specified by the plant operator, in ninety percent (90%) of all operating hours under normal operating conditions. This calculation will be adjusted to exclude forced outage periods and periods during which the RF/QF's output is affected by a Force Majeure event.

11. Completion/Performance Security

11.1 Simultaneous with the execution of this Contract RF/QF shall deliver to DEF Eligible Collateral in an amount equal to $30.00/kw of Committed Capacity as Completion/Performance Security.

11.2 The choice of the type of Eligible Collateral by the RF/QF may be selected from time to time by the RF/QF and upon receipt of substitute Eligible Collateral, DEF shall promptly release such Eligible Collateral. Following any termination of this Contract, the Parties shall mutually agree to a final settlement of all obligations under this Contract which such period shall not exceed 90 days from such termination date unless extended by mutual agreement between the Parties. After such settlement, any remaining Eligible Collateral posted by the RF/QF that has not been drawn upon by DEF pursuant to its rights under this Contract shall be returned to the RF/QF. Any dispute between the Parties regarding such final settlement shall be resolved according to applicable procedures set forth in Section 20.9.

11.3 Draws, Replenishment - DEF may draw upon Eligible Collateral provided by the RF/QF following the occurrence of an Event of Default or pursuant to the other provisions of this Contract in order to recover any damages to which DEF is entitled to under this Contract. In the event of such a draw then, except in the circumstance when this Contract otherwise terminates, the RF/QF shall within five (5) Business Days replenish the Eligible Collateral to the full amounts required.

DUKE ENERGY.

SECTION No. IX
~~FOURTH~~ FIFTH REVISED SHEET NO. 9.425
CANCELS ~~THIRD~~ FOURTH REVISED SHEET NO. 9.425

11.4 In the event that the (a) Capacity Delivery Date occurs before the Required Capacity Delivery Date and (b) the ACBF is equal to or greater than ~~94~~95% for the first twelve (12) months following the Capacity Delivery Date then DEF will return the Completion/Performance Security to the RF/QF within ninety (90) days of the first anniversary of the Capacity Delivery Date. In the event that the Capacity Delivery Date does not occur before the Required Capacity Delivery Date then DEF shall immediately be entitled to draw down the Completion/Performance Security in full. In the event that the ACBF is less than ~~94~~95% for any of the first twelve (12) months following the Capacity Delivery Date then DEF shall retain the Completion/Security until the ACBF is equal to or greater than ~~94~~95% for 12 consecutive months. Upon the completion of twelve (12) consecutive months with the ACBF greater than or equal to ~~94~~95% then DEF will return the Completion/Performance Security within ninety (90) days.

11.7 Reporting - RF/QF shall promptly notify DEF of any circumstance that results in RF/QF's failure to be in compliance with the RF/QF Performance Security Requirements of this Section 11. From time to time, at DEF's written request, RF/QF shall provide DEF with such evidence as DEF may reasonably request, that RF/QF Letter of Credit is in full compliance with this Contract.

12. Termination Fee and Security

12.1 In the event that the RF/QF receives Capacity Payments pursuant to Option B, Option C, or Option D of Appendix D or any Capacity Payment schedule in Appendix E that differs from a Normal Capacity Payment Rate as calculated in FPSC Rule 25-17.0832(6)(a), then upon the termination of this Contract, the RF/QF shall owe and be liable to DEF for the Termination Fee. The RF/QF's obligation to pay the Termination Fee shall survive the termination of this Contract. DEF shall provide the RF/QF, on a monthly basis, a calculation of the Termination Fee.

12.1.1 The Termination Fee shall be secured by the RF/QF by: (i) an unconditional, irrevocable, standby letter(s) of credit issued by a Qualified Institution in form and substance acceptable to DEF (including provisions (a) permitting partial and full draws and (b) permitting DEF to draw upon such Letter of Credit, in full, if such Letter of Credit is not renewed or replaced at least twenty (20) Business Days prior to its expiration date); (ii) a bond issued to DEF by a financially sound company in form and substance acceptable to DEF in its sole discretion; or (iii) a cash deposit with DEF (any of (i), (ii), or (iii), the "Termination Security").

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

12.1.2 DEF shall have the right and the RF/QF shall be required to monitor the financial condition of (i) the issuer(s) in the case of any Letter of Credit and (ii) the insurer(s), in the case of any bond. In the event the senior debt rating of any issuer(s) or insurer(s) has deteriorated to the extent that they fail to meet the requirements of a Qualified Institution, DEF may require the RF/QF to replace the letter(s) of credit or the bond, as applicable. In the event that DEF notifies the RF/QF that it requires such a replacement, the replacement letter(s) of credit or bond, as applicable, must be issued by a Qualified Institution, and meet the requirements of Section 12.1.1 within thirty (30) calendar days following such notification. Failure by the RF/QF to comply with the requirements of this Section 12.1.2 shall be grounds for DEF to draw in full on any existing Letter of Credit or bond and to exercise any other remedies it may have hereunder.

12.1.3 After the close of each calendar quarter (March 31, June 30, September 30, and December 31) occurring subsequent to the Capacity Delivery Date, upon DEF's issuance of the Termination Fee calculation as described in Section 12.1, the RF/QF must provide DEF, within ten calendar (10) days, written assurance and documentation (the "Security Documentation"), in form and substance acceptable to DEF, that the amount of the Termination Security is sufficient to cover the balance of the Termination Fee through the end of the following quarter. In addition to the foregoing, at any time during the term of this Contract, DEF shall have the right to request and the RF/QF shall be obligated to deliver within five (5) calendar days of such request, such Security Documentation. Failure by the RF/QF to comply with the requirements of this Section 12.1.3 shall be grounds for DEF to draw in full on any existing Letter of Credit or bond or to retain any cash deposit, and to exercise any other remedies it may have hereunder.

12.1.4 Upon any termination of this Contract following the Required Capacity Delivery Date, DEF shall be entitled to receive (and in the case of the Letter(s) of Credit or bond, draw upon such Letter(s) of Credit or bond) and retain one hundred percent (100%) of the Termination Security.

13. Performance Factor

DEF desires to provide an incentive to the RF/QF to operate the Facility during on-peak and off-peak periods in a manner that approximates the projected performance of the Avoided Unit. A formula to achieve this objective is attached as Appendix A.

14. Default

Notwithstanding the occurrence of any Force Majeure as described in Section 18, each of the following shall constitute an Event of Default:

(a) the RF/QF changes or modifies the Facility from that provided in Section 2 with respect to its type, location, technology or fuel source, without the prior written approval of DEF;

(b) after the Capacity Delivery Date, the Facility fails for twelve (12) consecutive months to maintain an Annual Capacity Billing Factor, as described in Appendix A, of at least seventy ~~four~~ five percent (~~74~~75%);

(c) the RF/QF fails to satisfy its obligations to maintain sufficient fuel on the site of the Facility to deliver the capacity and energy associated with the Committed Capacity for an uninterrupted seventy-two-(72) hour period under Section 10.5.6 hereof;

(d) the failure to make when due, any payment required pursuant to this Contract if such failure is not remedied within three (3) Business Days after written notice.

(e) either Party, or the entity which owns or controls either Party, ceases the conduct of active business; or if proceedings under the federal bankruptcy law or insolvency laws shall be instituted by or for or against either Party or the entity which owns or controls either Party; or if a receiver shall be appointed for either Party or any of its assets or properties, or for the entity which owns or controls either Party; or if any part of either Party's assets shall be attached, levied upon, encumbered, pledged, seized or taken under any judicial process, and such proceedings shall not be vacated or fully stayed within thirty (30) calendar days thereof; or if either Party shall make an assignment for the benefit of creditors, or admit in writing its inability to pay its debts as they become due;

(f) the RF/QF fails to give proper assurance of adequate performance as specified under this Contract within thirty (30) calendar days after DEF, with reasonable grounds for insecurity, has requested in writing such assurance;

(g) the RF/QF fails to achieve licensing, certification, and all federal, state and local governmental, environmental, and licensing approvals required to initiate construction of the Facility by no later than the Completed Permits Date;

(h) the RF/QF fails to comply with the provisions of Section 11 hereof;

(i) any of the representations or warranties, including the certification of the completion of the Conditions Precedent, made by either Party in this Contract is false or misleading in any material respect as of the time made;

(j) if, at any time after the Capacity Delivery Date, the RF/QF reduces the Committed Capacity due to an event of Force Majeure and fails to repair the Facility and reset the Committed Capacity to the level set forth in Section 7.2 (as such level may be reduced by Section 7.4) within twelve (12) months following the occurrence of such event of Force Majeure; or

(k) either Party breaches any material provision of this Contract not specifically mentioned in this Section 14;

(l) the RF/QF fails to maintain its status as a Qualifying Facility.

15. Rights in the Event of Default

15.1 Upon the occurrence of any of the Events of Default in Section 14, the DEF may, at its option:

15.1.1 immediately terminate this Contract, without penalty or further obligation, except as set forth in Section 15.2, by written notice to the RF/QF, and offset against any payment(s) due from DEF to the RF/QF, any monies otherwise due from the RF/QF to DEF;

15.1.2 enforce the provisions of the Completion/Performance Security pursuant to Section 11 and/or the Termination Security requirement pursuant to Section 12 hereof, as applicable; and

15.1.3 exercise any other remedy(ies) which may be available to DEF at law or in equity.

15.2 Termination shall not affect the liability of either Party for obligations arising prior to such termination or for damages, if any, resulting from any breach of this Contract.

16. Indemnification

16.1 DEF and the RF/QF shall each be responsible for its own facilities. DEF and the RF/QF shall each be responsible for ensuring adequate safeguards for other DEF customers, DEF's and the RF/QF's personnel and equipment, and for the protection of its own generating system. Each Party (the "Indemnifying Party") agrees, to the extent permitted by applicable law, to indemnify, pay, defend, and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors (hereinafter called respectively, "DEF Entities" and "RF/QF Entities") from and against any and all claims, demands, costs or expenses for loss, damage, or injury to persons or property of the Indemnified Party (or to third parties) directly caused by, arising out of, or resulting from:

(a) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(b) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation or operation of its generation system or the operation thereof in connection with the other Party's system;

(c) any defect in, failure of, or fault related to, the Indemnifying Party's generation system;

(d) the negligence or willful misconduct of the Indemnifying Party or its contractors, agents, servants or employees; or

(e) any other event or act that is the result of, or proximately caused by, the Indemnifying Party or its contractors, agents, servants or employees related to the Contract or the Parties' performance thereunder.

16.2 Payment by an Indemnified Party to a third party shall not be a condition precedent to the obligations of the Indemnifying Party under Section 16. No Indemnified Party under Section 16 shall settle any claim for which it claims indemnification hereunder without first allowing the Indemnifying Party the right to defend such a claim. The Indemnifying Party shall have no obligations under Section 16 in the event of a breach of the foregoing sentence by the Indemnified Party. Section 16 shall survive termination of this Contract.

17. Insurance

17.1 The RF/QF shall procure or cause to be procured and shall maintain throughout the entire Term of this Contract, a policy or policies of liability insurance issued by an insurer acceptable in the state of Florida on a standard "Insurance Services Office" commercial general liability and/or excess liability form or equivalent and Workers' Compensation in accordance with the statutory requirements of the state of Florida (such policy or policies, collectively, the "RF/QF Insurance"). A certificate of insurance shall be delivered to DEF at least fifteen (15) calendar days prior to the start of any interconnection work. At a minimum, the RF/QF Insurance shall contain (a) an endorsement providing coverage, including products liability/completed operations coverage for the term of this Contract, and (b) premises and operations liability, (c) a broad form contractual liability endorsement covering liabilities (i) which might arise under, or in the performance or nonperformance of, this Contract or (ii) caused by operation of the Facility or any of the RF/QF's equipment Without limiting the foregoing, the RF/QF Insurance must be reasonably acceptable to DEF. Any premium assessment or deductible shall be for the account of the RF/QF and not DEF.

17.2 The RF/QF Insurance for liability shall have a minimum limit of five million dollars ($5,000,000.00) per occurrence for bodily injury (including death) or property damage. This liability limit can be met by any combination of commercial general and excess liability insurance policies.

17.3 To the extent that the RF/QF Insurance is on a " claims made " basis, the retroactive date of the policy(ies) shall be the Effective Date of this Contract or an earlier date. Furthermore, to the extent the RF/QF Insurance is on a "claims made" basis, the RF/QF's duty to provide insurance coverage shall survive the termination of this Contract until the expiration of the maximum statutory period of limitations in the State of Florida for actions based in contract or in tort. To the extent the RF/QF Insurance is on an "occurrence" basis, such insurance shall be maintained in effect at all times by the RF/QF during the term of this Contract.

17.4 The RF/QF shall provide DEF with a copy of any material communication or notice related to the RF/QF Insurance within ten (10) Business Days of the RF/QF's receipt or issuance thereof.

17.5 DEF shall be designated as an additional named insured under the RF/QF Insurance (except Workers' Compensation). The RF/QF Insurance shall be be primary to any coverage maintained by DEF and provide, where permitted by law, waiver of any rights of subrogation against DEF. Any deductibles or retentions shall be the sole responsibility of RF/QF. RF/QF's compliance with these provisions and the limits of insurance specified herein shall not constitute a limitation of RF/QF's liability or otherwise affect RF/QF's indemnification obligations pursuant to this Contract. Any failure to comply with all of these provisions shall not be deemed a waiver of any rights of DEF under this Contractor with respect to any insurance coverage required hereunder. DEF may request the RF/QF to provide a copy of any or all of its required insurance policies, including endorsements in which DEF is included as an additional insured for any claims filed relative to this Contract.

18. Force Majeure

18.1 "Force Majeure" is defined as an event or circumstance that is not reasonably foreseeable, is beyond the reasonable control of and is not caused by the negligence or lack of due diligence of the Party claiming Force Majeure or its contractors or suppliers and adversely affects the performance by that Party of its obligations under or pursuant to this Contract. Such events or circumstances may include, but are not limited to, actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, blockades, embargoes, sabotage, epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes or difficulties (not caused by the failure of the affected party to comply with the terms of a collective bargaining agreement). Force Majeure shall not be based on (i) the loss of DEF's markets; (ii) DEF's economic inability to use or resell the Capacity and Energy purchased hereunder; or (iii) RF/QF's ability to sell the Capacity or Energy at a price greater than the price herein. Equipment breakdown or inability to use equipment caused by its design, construction, operation, maintenance or inability to meet regulatory standards, or otherwise caused by an event originating in the control of a Party, or a Party's failure to obtain on a timely basis and maintain a necessary permit or other regulatory approval, shall not be considered an event of Force Majeure, unless such Party can reasonably demonstrate, to the reasonable satisfaction of the non-claiming Party, that the event was not reasonably foreseeable, was beyond the Party's reasonable control and was not caused by the negligence or lack of due diligence of the Party claiming Force Majeure or its agents, contractors or suppliers and adversely affects the performance by that Party of its obligations under or pursuant to this Contract.

18.2 Except as otherwise provided in this Contract, each Party shall be excused from performance when its nonperformance was caused, directly or indirectly by an event of Force Majeure.

18.3 In the event of any delay or nonperformance resulting from an event of Force Majeure, the Party claiming Force Majeure shall notify the other Party in writing within five (5) Business Days of the occurrence of the event of Force Majeure, of the nature cause, date of commencement thereof and the anticipated extent of such delay, and shall indicate whether any deadlines or date(s), imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure requires. A Party claiming Force Majeure shall not be entitled to any relief therefore unless and until conforming notice is provided. The Party claiming Force Majeure shall notify the other Party of the cessation of the event of Force Majeure or of the conclusion of the affected Party's cure for the event of Force Majeure in either case within two (2) Business Days thereof.

18.4 The Party claiming Force Majeure shall use its best efforts to cure the cause(s) preventing its performance of this Contract; provided, however, the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unfavorable.

18.5 If the RF/QF suffers an occurrence of an event of Force Majeure that reduces the generating capability of the Facility below the Committed Capacity, the RF/QF may, upon notice to DEF temporarily adjust the Committed Capacity as provided in Sections 18.6 and 18.7. Such adjustment shall be effective the first calendar day immediately following DEF's receipt of the notice or such later date as may be specified by the RF/QF. Furthermore, such adjustment shall be the minimum amount necessitated by the event of Force Majeure.

18.6 If the Facility is rendered completely inoperative as a result of Force Majeure, the RF/QF shall temporarily set the Committed Capacity equal to 0 kW until such time as the Facility can partially or fully operate at the Committed Capacity that existed prior to the Force Majeure. If the Committed Capacity is 0 kW, DEF shall have no obligation to make Capacity Payments hereunder.

18.7 If, at any time during the occurrence of an event of Force Majeure or during its cure, the Facility can partially or fully operate, then the RF/QF shall temporarily set the Committed Capacity at the maximum capability that the Facility can reasonably be expected to operate.

18.8 Upon the cessation of the event of Force Majeure or the conclusion of the cure for the event of Force Majeure, the Committed Capacity shall be restored to the Committed Capacity that existed immediately prior to the Force Majeure. Notwithstanding any other provisions of this Contract, upon such cessation or cure, DEF shall have right to require a Committed Capacity Test to demonstrate the Facility's compliance with the requirements of this Section 18.8. Any such Committed Capacity Test required by DEF shall be additional to any Committed Capacity Test under Section 7.4.

18.9 During the occurrence of an event of Force Majeure and a reduction in Committed Capacity under Section 18.5 all Monthly Capacity Payments shall reflect, pro rata, the reduction in Committed Capacity, and the Monthly Capacity Payments will continue to be calculated in accordance with the pay-for-performance provisions in Appendix A.

18.10 The RF/QF agrees to be responsible for and pay the costs necessary to reactivate the Facility and/or the interconnection with DEF's system if the same is (are) rendered inoperable due to actions of the RF/QF, its agents, or Force Majeure events affecting the RF/QF, the Facility or the interconnection with DEF. DEF agrees to reactivate, at its own cost, the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by DEF or its agents.

19. Representations, Warranties, and Covenants of RF/QF

Each Party hereto represents and warrants that as of the Effective Date:

19.1 Organization, Standing and Qualification
DEF is a corporation duly organized and validly existing in good standing under the laws of Florida and has all necessary power and authority to carry on its business as presently conducted to own or hold under lease its properties and to enter into and perform its obligations under this Contract and all other related documents and agreements to which it is or shall be a Party. The RF/QF is a __________ (corporation, partnership, or other, as applicable) duly organized and validly existing in good standing under the laws of __________ and has all necessary power and authority to carry on its business as presently conducted to own or hold under lease its properties and to enter into and perform its obligations under this Contract and all other related documents and agreements to which it is or shall be a Party. Each Party is duly qualified or licensed to do business in the State of Florida and in all other jurisdictions wherein the nature of its business and operations or the character of the properties owned or leased by it makes such qualification or licensing necessary and where the failure to be so qualified or licensed would impair its ability to perform its obligations under this Contract or would result in a material liability to or would have a material adverse effect on the other Party.

19.2 Due Authorization, No Approvals, No Defaults

Each of the execution, delivery and performance by each Party of this Contract has been duly authorized by all necessary action on the part of such Party, does not require any approval, except as has been heretofore obtained, of the shareholders DEF or of the ___________ (shareholders, partners, or others, as applicable) of the RF/QF or any consent of or approval from any trustee, lessor or holder of any indebtedness or other obligation of such Party, except for such as have been duly obtained, and does not contravene or constitute a default under any law, the articles of incorporation of DEF or the _____________ (articles of incorporation, bylaws, or other as applicable) of such Party, or any agreement, judgment, injunction, order, decree or other instrument binding upon such Party, or subject the Facility or any component part thereof to any lien other than as contemplated or permitted by this Contract.

19.3 Compliance with Laws

Each party has knowledge of all laws and business practices that must be followed in performing its obligations under this Contract. Each party also is in compliance with all laws, except to the extent that failure to comply therewith would not, in the aggregate, have a material adverse effect on the other Party.

19.4 Governmental Approvals

Except as expressly contemplated herein, neither the execution and delivery by each Party of this Contract, nor the consummation by each Party of any of the transaction contemplated thereby, requires the consent or approval of, the giving of notice to, the registration with, the recording or filing of any document with, or the taking of any other action with respect to governmental authority, except with respect to permits (a) which have already been obtained and are in full force and effect or (b) are not yet required (and with respect to which the RF/QF has no reason to believe that the same will not be readily obtainable in the ordinary course of business upon due application therefore).

19.5 No Suits, Proceedings

There are no actions, suits, proceedings or investigations pending or, to the knowledge of each Party, threatened against it at law or in equity before any court or tribunal of the United States or any other jurisdiction which individually or in the aggregate could result in any materially adverse effect on each Party's business, properties, or assets or its condition, financial or otherwise, or in any impairment of its ability to perform its obligations under this Contract. Each Party has no knowledge of a violation or default with respect to any law which could result in any such materially adverse effect or impairment.

19.6 Environmental Matters

To the best of its knowledge after diligent inquiry, each Party knows of no (a) existing violations of any environmental laws at the Facility, including those governing hazardous materials or (b) pending, ongoing, or unresolved administrative or enforcement investigations, compliance orders, claims, demands, actions, or other litigation brought by governmental authorities or other third parties alleging violations of any environmental law or permit which would materially and adversely affect the operation of the Facility as contemplated by this Contract.

20. General Provisions

20.1 Project Viability

To assist DEF in assessing the RF/QF's financial and technical viability, the RF/QF shall provide the information and documents requested in Appendix C or substantially similar documents, to the extent the documents apply to the type of Facility covered by this Contract and to the extent the documents are available. All documents to be considered by DEF must be submitted at the time this Contract is presented to DEF. Failure to provide the following such documents may result in a determination of non-viability by DEF.

20.2 Permits

The RF/QF hereby agrees to obtain and maintain any and all permits, certifications, licenses, consents or approvals of any governmental authority which the RF/QF is required to obtain as a prerequisite to engaging in the activities specified in this Contract.

20.3 Project Management

If requested by DEF, the RF/QF shall submit to DEF its integrated project schedule for DEF's review within sixty (60) calendar days from the execution of this Contract, and a start-up and test schedule for the Facility at least sixty (60) calendar days prior to start-up and testing of the Facility. These schedules shall identify key licensing, permitting, construction and operating milestone dates and activities. If requested by DEF, the RF/QF shall submit progress reports in a form satisfactory to DEF every calendar month until the Capacity Delivery Date and shall notify DEF of any changes in such schedules within ten (10) calendar days after such changes are determined. DEF shall have the right to monitor the construction, start-up and testing of the Facility, either on-site or off-site. DEF's technical review and inspections of the Facility and resulting requests, if any, shall not be construed as endorsing the design thereof or as any warranty as to the safety, durability or reliability of the Facility.

The RF/QF shall provide DEF with the final designer's/manufacturer's generator capability curves, protective relay types, proposed protective relay settings, main one-line diagrams, protective relay functional diagrams, and alternating current and direct elementary diagrams for review and inspection at DEF no later than one hundred eighty (180) calendar days prior to the initial synchronization date.

20.4 Assignment

Either Party may not assign this Contract, without the other Party's prior written approval, which approval may not be unreasonably withheld or delayed.

20.5 Disclaimer

In executing this Contract, DEF does not, nor should it be construed, to extend its credit or financial support for benefit of any third parties lending money to or having other transactions with the RF/QF or any assigns of this Contract.

20.6 Notification

All formal notices relating to this Contract shall be deemed duly given when delivered in person, or sent by registered or certified mail, or sent by fax if followed immediately with a copy sent by registered or certified mail, to the individuals designated below. The Parties designate the following individuals to be notified or to whom payment shall be sent until such time as either Party furnishes the other Party written instructions to contact another individual:

For the RF/QF:	For DEF:
____________________	Duke Energy Florida
____________________	Cogeneration Manager DEF 155
____________________	299 First Avenue North
____________________	St. Petersburg, FL 33701

Contracts and related documents may be mailed to the address below or delivered during normal business hours (8:00 a.m. to 4:45 p.m.) to the visitors' entrance at the address below:

Florida Power Corporation
d/b/a Duke Energy Florida, Inc.
299 First Avenue North
St. Petersburg, FL 33701

Attention: Cogeneration Manager DEF 155

20.7 Applicable Law

This Contract shall be construed in accordance with and governed by the laws of the State of Florida, and the rights of the parties shall be construed in accordance with the laws of the State of Florida.

20.8 Taxation

In the event that DEF becomes liable for additional taxes, including interest and/or penalties arising from an Internal Revenue Services determination, through audit, ruling or other authority, that DEF's payments to the RF/QF for Capacity under Options B, C, or D of the Appendix D are not fully deductible when paid (additional tax liability), DEF may bill the RF/QF monthly for the costs, including carrying charges, interest and/or penalties, associated with the fact that all or a portion of these Capacity Payments are not currently deductible for federal and/or state income tax purposes. DEF, at its option, may offset or recoup these costs against amounts due the RF/QF hereunder. These costs would be calculated so as to place DEF in the same economic position in which it would have been if the entire Capacity Payments had been deductible in the period in which the payments were made. If DEF decides to appeal the Internal Revenue Service's determination, the decision as to whether the appeal should be made through the administrative or judicial process or both, and all subsequent decisions pertaining to the appeal (both substantive and procedural), shall rest exclusively with DEF.

20.9 Resolution of Disputes

20.9.1 Notice of Dispute

In the event that any dispute, controversy or claim arising out of or relating to this Contract or the breach, termination or validity thereof should arise between the Parties (a "Dispute"), the Party may declare a Dispute by delivering to the other Party a written notice identifying the disputed issue.

20.9.2 Resolution by Parties

Upon receipt of a written notice claiming a Dispute, executives of both Parties shall meet at a mutually agreeable time and place within ten (10) Business Days after delivery of such notice and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute. In such meetings and exchanges, a Party shall have the right to designate as confidential any information that such Party offers. No confidential information exchanged in such meetings for the purpose of resolving a Dispute may be used by a Party in litigation against the other Party. If the matter has not been resolved within thirty (30) Days of the disputing Party's notice having been issued, or if the Parties fail to meet within ten (10) Business Days as required above, either Party may initiate binding arbitration in St. Petersburg, Florida, conducted in accordance with the then current American Arbitration Association's ("AAA") Large, Complex Commercial Rules or other mutually agreed upon procedures.

O_n	=	total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year, of the Avoided Unit;
i_p	=	annual escalation rate associated with the plant cost of the Avoided Unit;
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Avoided Unit;
r	=	annual discount rate, defined as the utility's incremental after-tax cost of capital;
L	=	expected life of the Avoided Unit; and
n	=	year for which the Avoided Unit is deferred starting with the Avoided Unit In-Service Date and ending with the Termination Date.

CALCULATION OF FIXED VALUE OF DEFERRAL PAYMENTS - EARLY CAPACITY-OPTION B

Under the fixed value of deferral Option A, payments for firm capacity shall not commence until the in-service date of the Avoided unit(s). At the option of the RF/QF, however, DEF may begin making payments for capacity consisting of the capital cost component of the value of a year-by-year deferral of the Avoided Unit prior to the anticipated in-service date of the Avoided Unit. When such payments for capacity are elected, the avoided capital cost component of Capacity Payments shall be paid monthly commencing no earlier than the Capacity Delivery Date of the RF/QF, and shall be calculated as follows:

$$A_M = [A_c (1 + i_p)^{(m-1)} + A_o (1 + i_o)^{(m-1)}] / 12 \qquad \text{for } m = 1 \text{ to } t$$

Where:

A_M	=	monthly payments to be made to the RF/QF for each month of the contract year n, in dollars per kilowatt per month in which RF/QF delivers capacity pursuant to the early capacity option;
i_p	=	annual escalation rate associated with the plant cost of the Avoided Unit;
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Avoided Unit;

m = year for which the fixed value of deferral payments under the early capacity option are made to a RF/QF, starting in year one and ending in the year t;

t = the Term, in years, of the Contract:

A_c = $F[(1-R)/(1-R^t)]$

Where:

F = the cumulative present value, in the year that the contractual payments will begin, of the avoided capital cost component of Capacity Payments which would have been made had Capacity Payments commenced with the Avoided Unit In-Service Date;

R = $(1+i_p)/(1+r)$

r = annual discount rate, defined as DEF's incremental after-tax cost of capital; and

A_o = $G[(1-R)/(1-R^t)]$

Where:

G = The cumulative present value, in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of Capacity Payments which would have been made had Capacity Payments commenced with the Avoided Unit In-Service Date.

R = $(1+i_o)/(1+r)$

The currently approved parameters applicable to the formulas above are found in Schedule 2.

CALCULATION OF FIXED VALUE OF DEFERRAL PAYMENTS - LEVELIZED AND EARLY LEVELIZED CAPACITY - OPTION C & OPTION D, RESPECTIVELY

Monthly fixed value of deferral payments for levelized and early levelized capacity shall be calculated as follows:

$$P_L = (F / 12) \cdot [r / 1 - (1 + r)^{-t}] + O$$

Where:

P_L = the monthly levelized capacity payment, starting on or prior to the in-service date of DEF's Avoided Unit(s):

F = the cumulative present value, in the year that the contractual payments will begin, of the avoided capital cost component of the Capacity Payments which would have been made had the Capacity Payments not been levelized;

r = the annual discount rate, defined as DEF's incremental after-tax cost of capital;

t = the Term, in years of the Contract

O = the monthly fixed operation and maintenance component of the Capacity Payments, calculated in accordance with calculation of the fixed value of deferral payments for the levelized capacity or the early levelized capacity options.

RISK-RELATED GUARANTEES

With the exception of governmental solid waste facilities covered by FPSC Rule 25-17.091, FPSC Rule 25-17.0832 (4)(e)10 requires that, when fixed value of deferral payments - early capacity, levelized capacity, or early levelized capacity are elected, the RF/QF must provide a surety bond or equivalent assurance of securing the payment of a Termination Fee in the event the RF/QF is unable to meet the terms and conditions of its Contract. Depending on the nature of the RF/QF's operation, financial health and solvency, and its ability to meet the terms and conditions of the Contract, one of the following may constitute an equivalent assurance of payment:

(1) Bond;
(2) Cash deposit(s) with DEF;
(3) Unconditional, irrevocable, direct pay Letter of Credit;
(4) Unsecured promise by a municipal, county or state government to repay payments for early or levelized capacity in the event of default, in conjunction with a legally binding commitment from such government allowing the utility to levy a surcharge on either the electric bills of the government's electricity consuming facilities or the constituent electric customers of such government to assure that payments for early or levelized capacity are repaid;
(5) Unsecured promise by a privately-owned RF/QF to repay payments for early or levelized capacity in the event of default, in conjunction with a legally binding commitment from the owner(s) of the RF/QF, parent company, and/or subsidiary companies located in Florida to assure that payments for early, levelized or early levelized capacity are repaid; or
(6) Other guarantees acceptable to DEF.

DUKE ENERGY.

SECTION No. IX
FIRST REVISED SHEET NO. 9.466
CANCELS ORIGINAL SHEET NO. 9.466

DEF will cooperate with each RF/QF applying for fixed value of deferral payments under the early, levelized or early levelized capacity options to determine the exact form of an "equivalent assurance" for payment of the Termination Fee to be required based on the particular aspects of the RF/QF. DEF will endeavor to accommodate an equivalent assurance of repayment which is in the best interests of both the RF/QF and DEF's ratepayers.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
~~NINTH~~ TENTH REVISED SHEET NO. 9.467
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 9.467

SCHEDULE 2
TO RATE SCHEDULE COG-2CAPACITY OPTION PARAMETERS

FIXED VALUE OF DEFERRAL PAYMENTS -
NORMAL CAPACITY OPTION PARAMETERS

Where, for one year deferral:

			Value
VAC_m	=	DEF's value of avoided capacity and O&M, in dollars per kilowatt per month, during month m;	~~4.64~~4.82
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present valued to the middle of the first year;	~~1.298~~1.309
I_n	=	total direct and indirect cost, in mid-year dollars per kilowatt including AFUDC but excluding CWIP, of the Avoided Unit with an in-service date of year n;	~~713.38~~770.85
O_n	=	total fixed operation and maintenance expense, for the year n, in mid-year dollars per kilowatt per year, of the Avoided Unit:	~~5.90~~3.87
i_p	=	annual escalation rate associated with the plant cost of the Avoided Unit;	2.50%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Avoided Unit;	2.50%
r	=	annual discount rate, defined as DEF's incremental after-tax cost of capital;	6.~~95~~92%
L	=	expected life of the Avoided Unit;	35
n	=	year for which the Avoided Unit is deferred starting with the Avoided Unit In-Service Date and ending with the Termination Date.	2024

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

20.10 Limitation of Liability

IN NO EVENT SHALL DEF, ITS PARENT CORPORATION, OFFICERS, DIRECTORS, EMPLOYEES, AND AGENTS BE LIABLE FOR ANY INCIDENTAL, INDIRECT, SPECIAL, CONSEQUENTIAL, EXEMPLARY, PUNITIVE, OR MULTIPLE DAMAGES RESULTING FROM ANY CLAIM OR CAUSE OF ACTION, WHETHER BROUGHT IN CONTRACT, TORT (INCLUDING, BUT NOT LIMITED TO, NEGLIGENCE OR STRICT LIABILITY), OR ANY OTHER LEGAL THEORY.

20.11 Severability

If any part of this Contract, for any reason, is declared invalid or unenforceable by a public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Contract, which remainder shall remain in force and effect as if this Contract had been executed without the invalid or unenforceable portion.

20.12 Complete Agreement and Amendments

All previous communications or agreements between the Parties, whether verbal or written, with reference to the subject matter of this Contract are hereby abrogated. No amendment or modification to this Contract shall be binding unless it shall be set forth in writing and duly executed by both Parties. This Contract constitutes the entire agreement between the Parties.

20.13 Survival of Contract

Subject to the requirements of Section 20.4, this Contract, as it may be amended from time to time, shall be binding upon, and inure to the benefit of, the Parties' respective successors-in-interest and legal representatives.

20.14 Record Retention

Each Party shall maintain for a period of five (5) years from the date of termination hereof all records relating to the performance of its obligations hereunder.

20.15 No Waiver

No waiver of any of the terms and conditions of this Contract shall be effective unless in writing and signed by the Party against whom such waiver is sought to be enforced. Any waiver of the terms hereof shall be effective only in the specific instance and for the specific purpose given. The failure of a Party to insist, in any instance, on the strict performance of any of the terms and conditions hereof shall not be construed as a waiver of such Party's right in the future to insist on such strict performance.

20.16 Set-Off

DEF may at any time, but shall be under no obligation to, set off or recoup any and all sums due from the RF/QF against sums due to the RF/QF hereunder without undergoing any legal process.

20.17 Change in Environmental Law or Other Regulatory Requirements

(a) As used herein, "Change(s) in Environmental Law or Other Regulatory Requirements" means the enactment, adoption, promulgation, implementation, or issuance of, or a new or changed interpretation of, any statute, rule, regulation, permit, license, judgment, order or approval by a governmental entity that specifically addresses environmental or regulatory issues and that takes effect after the Effective Date.

(b) The Parties acknowledge that Change(s) in Environmental Law or Other Regulatory Requirements could significantly affect the cost of the Avoided Unit ("Avoided Unit Cost Changes") and agree that, if any such change(s) should affect the cost of the Avoided Unit more than the Threshold defined in Section 20.17(c) below, the Party affected by such change(s) may avail itself of the remedy set forth in Section 20.17(d) below as its sole and exclusive remedy.

(c) The Parties recognize and agree that certain Change(s) in Environmental Law or Other Regulatory Requirements may occur that do not rise to a level that the Parties desire to impact this Contract. Accordingly, the Parties agree that for the purposes of this Contract, such change(s) will not be deemed to have occurred unless the change in Avoided Cost resulting from such change(s) exceed a mutually agreed upon amount. This mutually agreed upon amount is attached to this Contract in Appendix E.

(d) If an Avoided Unit Cost Change meets the threshold set forth in Section 20.17(c) above, the affected Party may request the avoided cost payments under this Contract be recalculated and that the avoided cost payments for the remaining term of the Contract be adjusted based on the recalculation, subject to the approval of the FPSC. Any dispute regarding the application of this Section 20.17 shall be resolved in accordance with Section 20.9.

20.18 Provision of Information.

Within a reasonable period of time after receiving a written request therefore from the requesting Party, the other Party hereto shall provide the requesting Party with information that is reasonable and related to the non-requesting Party and/or the facilities or operations of the non-requesting Party that the requesting Party reasonably requires in order to comply with a Requirement of Law or any requirement of Generally Accepted Accounting Principles promulgated by the Financial Accounting Standards Board (or any successor thereto), (including, but not limited to, FIN 46-R) applicable to the requesting Party. In the event that a party requires information or reports that are not within its possession to meet financial reporting requirements, the parties will work in good faith to enable the requesting party to meet its financial reporting requirements.

IN WITNESS WHEREOF, the RF/QF has executed this Contract on the date set forth below.

RF/QF

____
Signature

____
Print Name

____
Title

____
Date

IN WITNESS WHEREOF, DEF has acknowledged receipt of this executed Contract.

DUKE ENERGY FLORIDA, INC.

____
Signature

____
Print Name

____
Title

____
Date

DUKE ENERGY.

SECTION No. IX
~~SIXTH~~ SEVENTH REVISED SHEET NO. 9.442
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 9.442

APPENDIX A

TO

DUKE ENERGY FLORIDA
RENEWABLE OR QUALIFYING FACILITY LESS THAN 100 KW
STANDARD OFFER CONTRACT

MONTHLY CAPACITY PAYMENT CALCULATION

Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Renewable Energy Producer or a Qualifying Facility less than 100 kW.

A. In the event that the ACBF is less than or equal to ~~74~~75%, then no Monthly Capacity Payment shall be due. That is:

MCP = 0

B. In the event that the ACBF is greater than ~~74~~75% but less than ~~94~~95%, then the Monthly Capacity Payment shall be calculated by using the following formula:

MCP = BCP x [1 - [5 x (.~~94~~95 - ACBF)] x CC

C. In the event that the ACBF is equal to or greater than ~~94~~95%, then the Monthly Capacity Payment shall be calculated by using the following formula:

MCP = BCP x CC

Where:

MCP	=	Monthly Capacity Payment in dollars.
BCP	=	Base Capacity Payment in $/kW/Month as specified in Appendix D or E.
CC	=	Committed Capacity in kW.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

DUKE ENERGY.

SECTION No. IX
SECOND REVISED SHEET NO. 9.443
CANCELS FIRST REVISED SHEET NO. 9.443

ACBF	=	Annual Capacity Billing Factor. The ACBF shall be the electric energy actually received by DEF for the 12 consecutive months preceding the date of calculation excluding any energy received during an event of Force Majeure in which the Committed Capacity is temporarily set equal to 0 kW, divided by the product of the Committed Capacity and the number of hours in the 12 consecutive months preceding the date of calculation excluding the hours during an event of Force Majeure in which the Committed Capacity is temporarily set equal to 0 kW. If an event of Force Majeure occurs during the 12 consecutive months preceding the date of calculation in which the Committed Capacity is temporarily set to a value greater than 0 kW then the 12 month rolling average will be pro-rated accordingly. During the first 12 consecutive Monthly Billing Periods commencing with the first Monthly Billing Period in which Capacity Payments are to be made, the calculation of 12-month rolling average ACBF shall be performed as follows (a) during the first Monthly Billing Period, the ACBF shall be equal to the Monthly Availability Factor; (b) thereafter, the calculation of the ACBF shall be computed by summing the electric energy actually received by DEF for the number of full consecutive months preceding the date of calculation excluding any energy received during an event of Force Majeure in which the Committed Capacity is temporarily set equal to 0 kW, divided by the product of the Committed Capacity and the number of hours in the number of full consecutive months preceding the date of calculation excluding the hours during an event of Force Majeure in which the Committed Capacity is temporarily set equal to 0 kW. If an event of Force Majeure occurs during the months preceding the date of calculation in which the Committed Capacity is temporarily set to a value greater than 0 kW then the 12 month rolling average will be pro-rated accordingly. This calculation shall be performed at the end of each Monthly Billing Period until enough Monthly Billing Periods have elapsed to calculate a true 12-month rolling average ACBF.
MAF	=	Monthly Availability Factor. The total energy received during the Monthly Billing Period for which the calculation is made, divided by the product of Committed Capacity times the total hours during the Monthly Billing Period.
Monthly Billing Period	=	The period beginning on the first calendar day of each calendar month, except that the initial Monthly Billing Period shall consist of the period beginning 12:01 a.m., on the Capacity Delivery Date and ending with the last calendar day of such month.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
THIRD REVISED SHEET 9.444
CANCELS SECOND REVISED SHEET NO. 9.444

APPENDIX B
TO
DUKE ENERGY FLORIDA
RENEWABLE OR QUALIFYING FACILITY LESS THAN 100 KW
STANDARD OFFER CONTRACT

TERMINATION FEE

Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Renewable Energy Producer or a Qualifying Facility less than 100 kW.

The "Termination Fee" shall be the sum of the values for each month beginning with the month in which the Capacity Delivery Date occurs through the month of the Termination Date (or month of calculation, as the case may be) computed according to the following formula:

$$\sum_{i=1}^{n} (MCP_i - MCPC_i) \cdot (1 + r)^{(n-i)}$$

with: MCPC = 0 for all periods prior to the in-service date of the Avoided Unit:

where

i	=	number of Monthly Billing Periods commencing with the Capacity Delivery Date (i.e., the month in which Capacity Delivery Date occurs = 1; the month following this month in which Capacity Delivery Date occurs = 2 etc.)
n	=	the number of Monthly Billing Periods which have elapsed from the month in which the Capacity Delivery Date occurs through the month of termination (or month of calculation, as the case may be)
r	=	DEF's incremental after-tax avoided cost of capital (defined as r in Appendix D).
MCP_i	=	Monthly Capacity Payment paid to RF/QFQF corresponding to the Monthly Billing Period i, calculated in accordance with Appendix A.
$MCPC_i$	=	Monthly Capacity Payment for Option A corresponding to the Monthly Billing Period i, calculated in accordance with this Contract.

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE: April 29, 2013

DUKE ENERGY.

SECTION No. IX
~~FIFTH~~ SIXTH REVISED SHEET NO. 9.445
CANCELS ~~FOURTH~~ FIFTH REVISED SHEET NO. 9.445

In the event that for any Monthly Billing Period, the computation of the value of the Termination Fee for such Monthly Billing Period (as set forth above) yields a value less than zero, the amount of the Termination Fee shall be decreased by the amount of such value expressed as a positive number (the "Initial Reduction Value"); provided, however, that such Initial Reduction Value shall be subject to the following adjustments (the Initial Reduction Value, as adjusted, the "Reduction Value"):

a. In the event that in the applicable Monthly Billing Period the Annual Capacity Billing Factor, as defined in Appendix A is less than or equal to ~~74~~75%, then the Initial Reduction Value shall be adjusted to equal zero (Reduction Value = 0), and the Termination Fee shall not be reduced for the applicable Monthly Billing Period.

b. In the event that in the applicable Monthly Billing Period the Annual Capacity Billing Factor , as defined in Appendix A, is greater than ~~74~~75% but less than ~~94~~95%, than the Reduction Value shall be determined as follows:

Reduction Value = Initial Reduction Value x [5 x (ACBF - .~~94~~95)]

For the applicable Monthly Billing period, the Termination Fee shall be reduced by the amount of such Reduction Value.

c. In the event that in the applicable Monthly Billing Period the Annual Capacity Billing Factor, as defined in Appendix A, is equal to or greater than ~~94~~95%, then the Initial Reduction Value shall not be adjusted (Reduction Value = Initial Reduction Value), and the Termination Fee shall be reduced for the applicable Monthly Billing period by the amount of the Initial Reduction Value.

In no event shall DEF be liable to the RF/QF at any time for any amount by which the Termination Fee, adjusted in accordance with the foregoing, is less than zero (0).

ISSUED BY: Javier Portuondo, Director, Rates & Regulatory Strategy - FL
EFFECTIVE:

DUKE ENERGY.

**APPENDIX C
TO
DUKE ENERGY FLORIDA
RENEWABLE OR QUALIFYING FACILITY LESS THAN 100 KW
STANDARD OFFER CONTRACT**

DETAILED PROJECT INFORMATION

Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Renewable Energy Producer or a Qualifying Facility less than 100 kW.

Each eligible Contract received by DEF will be evaluated to determine if the underlying RF/QF project is financially and technically viable. The RF/QF shall, to the extent available, provide DEF with a detailed project proposal which addresses the information requested below:

I. FACILITY DESCRIPTION

- Project Name
- Project Location

* Street Address
* Size Plot Plan
* Legal Description of Site

- Generating Technology
- Primary Fuel
- Alternate Fuel (if applicable)
- Committed Capacity
- Expected In-Service Date

- Contact Person

* Individual's Name and Title
* Company Name
* Address
* Telephone Number
* Fax Number

II. PROJECT PARTICIPANTS

- Indicate the entities responsible for the following project management activities and provide a detailed description of the experience and capabilities of the entities:

* Project Development
* Siting and Licensing the Facility
* Designing the Facility
* Constructing the Facility
* Securing the Fuel Supply
* Operating the Facility

- Provide details on all electrical facilities which are currently under construction or operational which were developed by the RF/QF.
- Describe the financing structure for the projects identified above, including the type of financing used, the permanent financing term, the major lenders and the percentage of equity invested at Financial Closing.

III. FUEL SUPPLY

- Describe all fuels to be used to generate electricity at the Facility. Indicate the specific physical and chemical characteristics of each fuel type (*e.g.* Btu content, sulfur content, ash content, etc.). Identify special considerations regarding fuel supply origin, source and handling, storage and processing requirements.

- Provide AFR necessary to support planned levels of generation and list the assumptions used to determine these quantities.

- Provide a summary of the status of the fuel supply arrangements in place to meet the AFR, in each year of the proposed operating life of the Facility. Use the categories below to describe the current arrangement for securing the AFR.

Category	Description of Fuel Supply Arrangement
owned =	fuel is from a fully developed source owned by one or more of the project participants
contract =	fully executed firm fuel contract exists between the developer(s) and fuel supplier(s)
LOI =	a letter of intent for fuel supply exists between developer(s) and fuel supplier(s)
SPP =	small power production facility will burn biomass, waste, or another renewable resource
spot =	fuel supply will be purchased on the spot market
none =	no firm fuel supply arrangement currently in place
other =	fuel supply arrangement which does not fit any of the above categories (please describe)

- Indicate the percentage of the Facility's AFR which is covered by the above fuel supply arrangement(s) for each proposed operating year. The percent of AFR covered for each operating year must total 100%. For fuel supply arrangements identified as owned, contract, or LOI, provide documentation to support this category and explain the fuel price mechanism of the arrangement. In addition, indicate whether or not the fuel price includes delivery and, if so, to what location.

- Describe fuel transportation networks available for delivering all primary and secondary fuel to the Facility site. Indicate the mode, route and distance of each segment of the journey, from fuel source to the Facility site. Discuss the current status and pertinent factors impacting future availability of the transportation network.

- Provide AFTR necessary to support planned levels of generation and list the assumptions used to determine these quantities.

- Provide a summary of the status of the fuel transportation arrangements in place to meet the AFTR in each year of the proposed operating life of the Facility. Use the categories below to describe the current arrangement for securing the AFTR.

owned =	fuel transport via a fully developed system owned by one or more of the project participants
contract =	fully executed firm transportation contract exists between the developer(s) and fuel transporter(s)
LOI =	a letter of intent for fuel transport exists between developer(s) and fuel transporter(s)
spot =	fuel transportation will be purchased on the spot market
none =	no firm fuel transportation arrangement currently in place
other =	fuel transportation arrangement which does not fit any of the above categories (please describe)

- Provide the maximum, minimum and average fuel inventory levels to be maintained for primary and secondary fuels at the Facility site. List the assumptions used in determining the inventory levels.

- Provide information regarding RF/QF's plans to maintain sufficient on site fuel to deliver capacity and energy for an uninterrupted seventy-two (72) hour period.

IV. PLANT DISPATCHABILITY/CONTROLLABILITY

- Provide the following operating characteristics and a detailed explanation supporting the performance capabilities indicated:

  * Ramp Rate (MW/minute)
  * Peak Capability (% above Committed Capacity)
  * Minimum power level (% of Committed Capacity)
  * Facility Turnaround Time, Hot to Hot (hours)
  * Start-up Time from Cold Shutdown (hours)
  * Unit Cycling (# cycles/yr.)
  * MW and MVAR Control (ACC, Manual, Other (please explain))

V. SITING AND LICENSING

- Provide a licensing/permitting milestone schedule, which lists all permits, licenses and variances, required to site the Facility. The milestone schedule shall also identify key milestone dates for baseline monitoring, application preparation, agency review, certification and licensing/siting board approval, and agency permit issuance.

- Provide a licensing/permitting plan that addresses the issues of air emission, water use, wastewater discharge, wetlands, endangered species, protected properties, surrounding land use, zoning for the Facility, associated linear facilities and support of and opposition to the Facility.

- List the emission/effluent discharge limits the Facility will meet and describe in detail the pollution control equipment to be used to meet these limits.

VI. FACILITY DEVELOPMENT AND PERFORMANCE

- Submit a detailed engineering, procurement, construction, startup and commercial operation schedule. The schedule shall include milestones for site acquisition, engineering phases, selection of the major equipment vendors, architect engineer, and Facility operator, steam host integration and delivery of major equipment. A discussion of the current status of each milestone should also be included where applicable.

- Attach a diagram of the power block arrangement. Provide a list of the major equipment vendors and the name and model number of the major equipment to be installed.

- Provide a detailed description of the proposed environmental control technology for the Facility and describe the capabilities of the proposed technology.

- Attach preliminary flow diagrams for the steam system, water system, and fuel system, and a main electrical one line diagram for the Facility.

- State the expected heat rate (HHV) at 75 degrees Fahrenheit for loads of 100%, 75% and 50%. In addition, attach a preliminary heat balance for the Facility.

VII. FINANCIAL

- Provide DEF with assurances that the proposed RF/QF project is financially viable in accordance with FPSC Rule 25-17.0832(4)(c) by attaching a detailed pro-forma cash flow analysis. The pro-forma must include, at a minimum, the following assumptions for each year of the project.

- Annual Project Revenues

    * Capacity Payments ($ and $/kW/Mo.)
    * Variable O&M ($ and $/MWh)
    * Energy ($ and $/MWh)
    * Tipping Fees ($ and $/ton)
    * Interest Income
    * Other Revenues
    * Variable O&M Escalation (%/yr.)
    * Energy Escalation (%/yr.)
    * Tipping Fee Escalation (%/yr.)

- Annual Project Expense

    * Fixed O&M ($ and $/kW/Mo.)
    * Variable O&M ($ and $/MWh)
    * Energy ($ and $/MWh)
    * Property Taxes ($)
    * Insurance ($)
    * Emission Compliance ($ and $/MWh)
    * Depreciation ($ and %/yr.)
    * Other Expenses ($)
    * Fixed O&M Escalation (%/yr.)
    * Variable O&M Escalation (%/yr.)
    * Energy Escalation (%/yr.)

- Other Project Information

    * Installed Cost of the Facility ($ and $/kW)
    * Committed Capacity (kW)
    * Average Heat Rate - HHV (MBTU/kWh)
    * Federal Income Tax Rate (%)
    * Facility Capacity Factor (%)
    * Energy Sold to DEF (MWh)

- Permanent Financing

    * Permanent Financing Term (yr.)
    * Project Capital Structure (percentage of long-term debt, subordinated debt, tax exempt debt and equity)
    * Financing Costs (cost of long-term debt, subordinated debt, tax exempt debt and equity)
    * Annual Interest Expense
    * Annual Debt Service ($)
    * Amortization Schedule (beginning balance, interest expense, principal reduction, ending balance)

- Provide details of the financing plan for the project and indicate whether the project will be non-recourse project financed. If it will not be project financed please explain the alternative financing arrangement.
- Submit financial statements for the last two years on the principals of the project, and provide an illustration of the project ownership structure.

Item 9

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (M.Watts, King)
Division of Accounting and Finance (Golden)
Division of Economics (Bruce)
Office of the General Counsel (Tan, Lherisson)

RE: Docket No. 150199-WU – Application for staff-assisted rate case in Lake County by Raintree Waterworks, Inc.

AGENDA: 06/09/16 – Proposed Agency Action – Except for Issue Nos. 9, 11, and 12 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: 02/02/2017 (15-Month Effective Date (SARC))

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

Raintree Waterworks, Inc., (Raintree or Utility) is a Class C utility providing water service to approximately 109 residential customers and one general service customer in Lake County. The Utility was initially granted a small system exemption from Florida Public Service Commission (Commission) regulation in 1987 to serve 29 lots in the first phase of the development.[1] The Utility began providing water service in January 1988. In 1991, the Utility began working on the second phase of the development to expand service to 119 lots, and subsequently filed an application for a water certificate since it would no longer be eligible for the small system exemption. The Utility was granted Certificate No. 539-W in 1992.[2] Rates were last established for this Utility in 2008, when it was known as Raintree Utilities, Inc.[3] The Utility was transferred to Raintree Harbor Utilities, LLC in 2012,[4] and to Raintree in 2014.[5]

On September 11, 2015, Raintree filed an application for a staff assisted rate case (SARC). Staff selected the test year ending July 31, 2015, for the instant case. According to Raintree's 2015 annual report, its total operating revenues were $42,210. The Utility reported a net income of $1,547.[6]

A customer meeting was held on March 9, 2016, at the Tavares Community Center to receive customer questions and comments concerning the Utility's rate case and quality of service. The Commission has jurisdiction in this case pursuant to Section 367.0814, Florida Statutes, (F.S.).

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[1]Order No. 18131, issued September 8, 1987, in Docket No. 870796-WU, *In re: Petition of Raintree Harbor Phase I for determination of exempt status of a water facility in Lake County.*
[2]Order No. PSC-92-0019-FOF-WU, issued March 10, 1992, in Docket No. 911039-WU, *In re: Application of Raintree Utilities, Inc. for a water certificate in Lake County, Florida.*
[3]Order No. PSC-08-0483-PAA-WU, issued July 25, 2008, in Docket No. 070627-WU, *In re: Application for staff-assisted rate case in Lake County by Raintree Utilities, Inc.*
[4]Order No. PSC-12-0260-PAA-WU, issued May 29, 2012, in Docket No. 110302-WU, *In re: Application by Raintree Utilities, Inc. in Lake County for the transfer of the Bentwood water facilities to the Bentwood Homeowners Association, Inc., and the transfer of the Raintree Harbor water facilities and Certificate No. 539-W to Raintree Harbor Utilities, LLC.*
[5]Order No. PSC-14-0692-PAA-WU, issued December 15, 2014, in Docket No. 140121-WU, *In re: Application for approval of transfer of Certificate No. 539-W from Raintree Harbor Utilities, LLC to Raintree Waterworks, Inc. in Lake County.*
[6]Raintree Waterworks, Inc. 2015 Annual Report filed March 8, 2016, with the Commission.
http://www.floridapsc.com/library/financials/WU969-DOCS/ANNUAL-REPORTS/WU969-15-AR.PDF

Discussion of Issues

Issue 1: Should the quality of service provided by Raintree be considered satisfactory?

Recommendation: Yes. The overall quality of service provided by Raintree should be considered satisfactory. (M.Watts)

Staff Analysis: Pursuant to Rule 25-30.433(1), Florida Administrative Code (F.A.C.), in water and wastewater rate cases, the Commission shall determine the overall quality of service provided by the Utility. This is derived from an evaluation of three separate components of the Utility's operations. These components are: (1) the quality of the utility's product; (2) the operating conditions of the utility's plant and facilities; and (3) the utility's attempt to address customer satisfaction. The rule further states that sanitary surveys, outstanding citations, violations, and consent orders on file with the Department of Environmental Protection (DEP) and the county health department over the preceding three-year period shall be considered. Additionally, Section 367.0812(1)(c), F.S., requires the Commission to consider the extent to which the utility provides water service that meets secondary water quality standards as established by the DEP.

Quality of Utility's Product

Staff's evaluation of Raintree's water quality consisted of a review of the Utility's compliance with the DEP primary and secondary drinking water standards and customer complaints. Primary standards protect public health while secondary standards regulate contaminants that may impact the taste, odor, and color of drinking water.

Based on staff's review of DEP records, the Utility was in compliance with all primary and secondary standards during the three-year period (2012-2014) that preceded the test year. On April 27, 2015, water testing for primary and secondary water standards was conducted by Advanced Environmental Laboratories, Inc., and all results remained in compliance with the DEP primary and secondary water quality standards.

Staff's review of complaints filed with the Commission (none were filed with DEP), did not reveal any issues or concerns regarding the quality of Raintree's product. Based on staff's review, giving consideration to the Utility's current compliance with DEP standards, as well as the lack of customer complaints, the quality of Raintree's product should be considered satisfactory.

Operating Condition of the Utility's Plant and Facilities

Raintree provides finished potable water obtained from three wells, which draw ground water from the aquifer. The raw water is treated by reverse osmosis chlorination filtration and pumped into a 3,000 gallon hydropneumatic tank and then into the distribution system. The distribution system is composed of PVC pipe. Staff's evaluation of Raintree's facilities included a review of the Utility's compliance standards of operation as well as a site visit.

On October 11, 2013, DEP conducted a sanitary survey, and found one deficiency, stating that the Well #1 check valve was not holding. The survey report, issued on January 16, 2014, stated that the Utility advised that the check valve was replaced on October 14, 2013, and deemed the water treatment plant in compliance. Staff did not identify any issues or concerns during its March 9, 2016, site visit. Therefore, the operating condition of Raintree's water treatment plant and facilities should be considered satisfactory.

The Utility's Attempt to Address Customer Satisfaction

The final component of the overall quality of service that must be assessed is customer satisfaction. As part of staff's evaluation of customer satisfaction, staff held a customer meeting (March 9, 2016) to receive customer comments concerning Raintree's quality of service. The Utility mailed the customer meeting notice to its customers on February 17, 2016, advising them of the time, place, and purpose of the meeting, as well as the procedures for filing comments with the Commission. No customers attended the meeting, and, as of the filing date of this recommendation, no customer correspondence has been received.

Staff also requested copies of complaints filed with the Utility during the test year and four years prior to the test year. The Utility responded on February 8, 2016, with the complaints that it had received since it acquired the Utility in 2014. The response shows 34 customer contacts, 21 of which were related to two general power outage events that occurred on May 22 and September 1, 2015, that affected the water treatment plant. Seven complaints were for leaks. The Utility investigated and either fixed the leak or advised that it was on the customer's side of the meter, as appropriate. One of the leaks was found to be a wastewater leak which did not involve Raintree's system. Three customer contacts were regarding water service that had been shut off due to nonpayment, and were resolved when payment was made. The last three customer contacts regarded a quality of service issue that Raintree tried to follow up on to obtain additional information, but the customers in each case failed to pursue the matter.

On April 26, 2016, staff requested complaints against the system filed with the DEP for the test year and four years prior. DEP responded on May 9, 2016, stating that it had received no complaints against the system in the last five years.

Finally, staff reviewed the Commission's complaint records from January 1, 2010, through May 9, 2016. There were no complaints filed against any of the three utilities that had ownership of the water system during this period. Therefore, staff recommends the Utility's attempt to address customer satisfaction should be considered satisfactory.

Conclusion

Based on the summation of staff's analysis and review described above, the overall quality of service provided by Raintree should be considered satisfactory.

Issue 2: What are the used and useful percentages (U&U) of Raintree's water treatment plant and distribution system?

Recommendation: Raintree's water treatment plant (WTP) and distribution system should be considered 100 percent U&U. Staff recommends that WTP purchased power and chemical expenses should be reduced by 8.5 percent for excessive unaccounted for water (EUW). (M. Watts)

Staff Analysis: Raintree's water system is served by two 4-inch wells and one 8-inch diameter well rated at 88, 88, and 90 gallons per minute, respectively. The raw water is treated by reverse osmosis chlorination filtration prior to entering the 3,000-gallon hydropneumatic tank for pressurization, and then pumped into the water distribution system. The Utility is permitted to withdraw an average of 0.062 million gallons per day for the years 2014 through 2028. Analysis of the system indicates there has been no growth of the system in the past five years. Staff notes that Raintree's water treatment plant and distribution system were deemed 100 percent U&U in the Utility's previous SARC.

Water Treatment Plant and Distribution System Used & Useful

As noted above, the Commission found both the water treatment plant and distribution system to be 100 percent U&U in the prior SARC. There have been no major plant additions or growth in the last five years. Therefore, consistent with the prior Commission decision, the water treatment plant and distribution system should be considered 100 percent U&U.

Excessive Unaccounted for Water

Pursuant to Rule 25-30.4325, F.A.C., the calculation of U&U for a water treatment plant must consider EUW. Rule 25-30.4325, F.A.C., describes EUW as unaccounted for water in excess of 10 percent of the amount produced. When establishing the Rule, the Commission recognized that some uses of water are readily measurable and others are not.[7] Unaccounted for water is all water that is produced that is not sold, metered or accounted for in the records of the Utility. The unaccounted for water is calculated by subtracting both the gallons used for other purposes, such as flushing, and the gallons sold to customers from the total gallons pumped for the test year. The Rule additionally provides that to determine whether adjustments to plant and operating expenses, such as purchased electrical power and chemicals cost, are necessary, the Commission will consider all relevant factors as to the reason for EUW, solutions implemented to correct the problem, or whether a proposed solution is economically feasible.

While reviewing the Utility's filing, staff noted that Raintree reported that it sold more water in June and July of 2015 than it produced. Staff requested clarification of this data, and the Utility reported that Well #3's flow meter had been inoperable for several months, and during that time the flows from that well were estimated. The Utility attached an invoice showing that the flow

[7]Order No. PSC-93-0455-NOR-WS, issued on March 24, 1993, in Docket No. 911082-WS, *In re: Proposed revisions to Rules 25-22.0406, 25-30.020, 25-30.025, 25-30.030, 25-30.032 through 25-30.037, 25-30.060, 25-30.110, 25-30.111, 25-30.135, 25-30.255, 25-30.320, 25-30.335, 25-30.360, 25-30.430, 25-30.436, 25-30.437, 25-30.443, 25-30.455, 25-30.515, 25-30.565; adoption of Rules 25-22.0407, 25-22.0408, 25-22.0371, 25-30.038, 25-30.039, 25-30.090, 25-30.117, 25-30.432 through 25-30.435, 25-30.4385, 25-30.4415, 25-30.456, 25-30.460, 25-30.465, 25-30.470, 25-30.475; and repeal of Rule 25-30.441, F.A.C., pertaining to water and wastewater regulation*, at p. 102.

meter was replaced on November 18, 2015, and requested it be included as pro forma in the instant docket. Staff agrees that the flow meter repair is necessary and should be included as pro forma as requested.

Since the actual amount of water produced by Well #3 during June and July of 2015 cannot be determined, staff excluded those months from its EUW calculations. Therefore, based on the ten-month period during the test year of August 1, 2014, to May 31, 2015, the Utility's Monthly Operating Reports filed with DEP indicate that it treated 13,035,970 gallons. The Utility sold 10,140,000 gallons of water for the stated ten-month period. The Utility reported that it used 488,349 gallons for other uses. Adding the water sold to the water used for other uses, and subtracting the sum from the amount produced yields an unaccounted for water total of 2,407,621 gallons, or 18.5 percent, yielding an EUW of 8.5 percent. Therefore, staff recommends that an 8.5 percent adjustment be made to operating expenses for chemicals and purchased power due to EUW.

Conclusion

Raintree's WTP and distribution system should be considered 100 percent U&U. Staff recommends that WTP purchased power and chemical expenses should be reduced by 8.5 percent for EUW.

Issue 3: What is the appropriate average test year rate base for Raintree?

Recommendation: The appropriate average test year rate base for Raintree is $51,282. (Golden)

Staff Analysis: The appropriate components of the Utility's rate base include utility plant in service, land, contributions-in-aid-of-construction (CIAC), accumulated depreciation, amortization of CIAC, and working capital. Raintree's net book value was last determined by Order No. PSC-14-0692-PAA-WU in a 2014 certificate transfer docket.[8] Rate base was last established in the Utility's last SARC in 2008.[9] Staff selected the test year ending July 31, 2015, for the instant case. Commission audit staff determined that the Utility's books and records are in compliance with the National Association of Regulatory Utility Commissioners' Uniform System of Accounts (NARUC USOA). A summary of each component of rate base and the recommended adjustments are discussed below.

Utility Plant in Service (UPIS)

The Utility recorded $252,519 in UPIS. Staff decreased UPIS by $750 to reclassify Raintree's 2014 certificate transfer application filing fee from plant Account No. 302 – Franchises to expense Account No. 665 – Regulatory Commission Expense. Although the NARUC USOA allows the filing fee to be recorded as either a plant or expense item, current Commission practice is to record this type of filing fee as a non-recurring expense. This enables the Utility to recover the filing fee over 5 years, rather than 40 years associated with plant Account No. 302. This approach is particularly helpful to Class C utilities which often operate with limited cash resources. The exception is that the filing fee for an original certificate application for a utility that has not been built yet will typically be recorded to plant Account No. 301 – Organization as part of the cost to establish a new utility.

As discussed in Issue 2, the Utility replaced an inoperable flow meter subsequent to the test year. In its response to Staff's First Data Request, the Utility requested recovery of the repair as a pro forma plant item and provided supporting documentation.[10] Based on engineering staff's review, staff increased UPIS by $929 to reflect the pro forma replacement of the new flow meter. It is Commission practice to use 75 percent of the cost of the replacement as the retirement value when the original cost or original in-service date is not known. Accordingly, staff decreased this account by $697 ($929 x .75 = $697) to reflect the plant retirement associated with the flow meter replacement. According to Raintree's 2015 Annual Report, the Utility also recorded this replacement using a 75 percent retirement value. No plant additions were made during the test year, therefore, no averaging adjustment is necessary for ratemaking purposes. Staff's net adjustment to UPIS is a decrease of $518. Therefore, staff recommends a UPIS balance of $252,001.

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[8]Order No. PSC-14-0692-PAA-WU, issued December 15, 2014, in Docket No. 140121-WU, *In re: Application for approval of transfer of Certificate No. 539-W from Raintree Harbor Utilities, LLC to Raintree Waterworks, Inc. in Lake County.*
[9]Order No. PSC-08-0483-PAA-WU, issued July 25, 2008, in Docket No. 070627-WU, *In re: Application for staff-assisted rate case in Lake County by Raintree Utilities, Inc.*
[10]Document No. 00750-16, filed on February 8, 2016, in Docket No. 150199-WU.

Land and Land Rights

The Commission approved a land balance of $5,740 in the Utility's 2014 transfer docket. Audit staff determined that there has been no subsequent activity related to land, therefore, no adjustments are necessary. Staff recommends a land and land rights balance of $5,740.

Non-Used and Useful Plant

As discussed in Issue 2, Raintree's water treatment plant and distribution system are considered 100 percent U&U. Therefore, a U&U adjustment is not necessary.

Contribution in Aid of Construction

The Commission approved a CIAC balance of $29,750 in the Utility's 2014 transfer docket. Audit staff determined there has been no subsequent activity related to CIAC, therefore, no adjustments are necessary. Staff recommends a CIAC balance of $29,750.

Accumulated Depreciation

The Utility recorded $201,496 in accumulated depreciation. Staff calculated accumulated depreciation using the prescribed rates set forth in Rule 25-30.140, F.A.C. Staff's calculation includes a $22 decrease to remove the accumulated depreciation associated with the $750 filing fee reclassification discussed above. However, that decrease is offset by a total of $22 in minor increases to four other accounts, resulting in no change to total accumulated depreciation for the test year. Consequently, no adjustments are needed to correct the test year balance for rate setting purposes. As will be discussed further in Issue 12, staff's adjusted account balances for the test year are reflected on Schedule No. 5 to assist the Utility with adjusting its books and records.

In addition, staff recommends two pro forma adjustments associated with the flow meter replacement discussed above. Staff decreased this account by $697 to remove the accumulated depreciation associated with the retired flow meter. Staff also increased this account by $7 to reflect the minor incremental increase in accumulated depreciation associated with the new flow meter. Finally, staff decreased the test year total accumulated depreciation by $5,419 to reflect an averaging adjustment. Staff's net adjustment to this account is a decrease of $6,109. Therefore, staff recommends an accumulated depreciation balance of $195,387.

Accumulated Amortization of CIAC

Raintree recorded an amortization of CIAC balance of $15,143. Staff calculated amortization of CIAC using composite depreciation rates, and determined that no adjustments are necessary. Staff decreased this account by $640 to reflect an averaging adjustment. Staff recommends an accumulated amortization of CIAC balance of $14,503.

Working Capital Allowance

Working capital is defined as the investor-supplied funds that are necessary to meet operating expenses of the utility. Consistent with Rule 25-30.433(2), F.A.C., staff used the one-eighth of the operation and maintenance (O&M) expense formula approach for calculating the working capital allowance. Applying this formula, staff recommends a working capital allowance of $4,175 (based on O&M expense of $33,402/8).

Rate Base Summary

Based on the foregoing, staff recommends that the appropriate average test year rate base is \$51,282. Rate base is shown on Schedule No. 1-A. The related adjustments are shown on Schedule No. 1-B.

Issue 4: What is the appropriate rate of return on equity and overall rate of return for Raintree?

Recommendation: The appropriate return on equity (ROE) is 8.74 percent with a range of 7.74 percent to 9.74 percent. The appropriate overall rate of return is 8.74 percent. (Golden)

Staff Analysis: Raintree's capital structure consists of $49,929 in common equity. Audit staff verified that the Utility has no debt. In addition, audit staff verified that the Utility does not collect customer deposits and does not have a tariff in effect for customer deposits. Therefore, no adjustments are necessary.

The Utility's capital structure has been reconciled with staff's recommended rate base. The appropriate ROE is 8.74 percent based upon the Commission-approved leverage formula currently in effect.[11] Staff recommends an ROE of 8.74 percent, with a range of 7.74 percent to 9.74 percent, and an overall rate of return of 8.74 percent. The ROE and overall rate of return are shown on Schedule No. 2.

[11]Order No. PSC-15-0259-PAA-WS, issued July 2, 2015, in Docket No. 150006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

Issue 5: What is the appropriate test year revenue for Raintree's water system?

Recommendation: The appropriate test year revenue for Raintree's water system is $42,540. (Bruce)

Staff Analysis: Raintree recorded a total revenue of $40,670. The water revenue included $40,660 of service revenues and $10 of miscellaneous revenues. In order to determine the appropriate service revenues, staff corrected billing determinants to reflect credits issued to customers. During the test year, the Utility had a rate increase as a result of a price index. Therefore, staff annualized test year revenue by applying the rates in effect as of June 26, 2015, to staff's adjusted billing determinants. Based on the corrected billing determinants, staff determined that service revenues should be $42,322, which is an increase of $1,652.

On July 15, 2015, the Utility began charging a $2.60 convenience charge to customers who opted to pay their water bill online or by way of telephone.[12] During the test year, there were only four occurrences. However, since the implementation of the convenience charge through March of 2016, there were approximately 66 occurrences. In order to recognize the revenues associated with this charge on a going forward basis, staff annualized the number of occurrences. As a result, the approximate annual average of occurrences is 84, which calculates to be $218 of miscellaneous revenues. Therefore, staff increased miscellaneous revenues by $208 ($218-$10). The appropriate test year revenue for Raintree's water system, including miscellaneous revenues, is $42,540 ($42,322+$218).

[12]Order No. PSC-15-0190-TRF-WU, issued May 6, 2015, in Docket No. 150062-WU, *In re: Request for approval of amendment to tariff for miscellaneous service charges in Lake County by Raintree Waterworks, Inc.*

Issue 6: What is the appropriate amount of operating expenses?

Recommendation: The appropriate amount of operating expense for the Utility is $42,568. (Golden)

Staff Analysis: Raintree recorded operating expense of $46,531 for the test year ended July 31, 2015. The test year O&M expenses have been reviewed, including invoices, canceled checks, and other supporting documentation. Staff has made several adjustments to the Utility's operating expenses as summarized below.

Operation and Maintenance Expenses

Purchased Power (615)

Raintree recorded $4,689 for test year purchased power expense. As discussed in Issue 2, staff is recommending an EUW adjustment of 8.5 percent. Therefore, staff decreased this account by $399 ($4,689 x .085 = $399) to reflect an 8.5 percent EUW adjustment. Therefore, staff recommends purchased power expense of $4,290.

Chemicals (618)

The Utility recorded $345 for test year chemicals expense. As discussed in Issue 2, staff is recommending an EUW adjustment of 8.5 percent. Therefore, staff decreased this account by $29 ($345 x .085 = $29) to reflect an 8.5 percent EUW adjustment. Therefore, staff recommends purchased power expense of $316.

Contractual Services - Professional (631)

Raintree recorded $2,107 for test year contractual services – professional expense, comprised of $1,667 in accrued accounting expense and $440 in legal expense. The Utility's actual test year accounting services expense was $1,000, therefore, staff decreased this account by $667 to remove the excess accrued accounting expense. Staff recommends contractual services – professional expense for the test year of $1,440.

Contractual Services - Other (636)

The Utility recorded $21,744 in this account. Raintree receives all of its operational and administrative services under a contract with an affiliated company, U.S. Water Services Corporation (USWSC). The Commission previously reviewed and approved expenses related to the USWSC management services contracts for five of Raintree's sister utilities.[13] In the three most recent related dockets, the Commission found USWSC's costing and allocation model to be

[13]Order No. PSC-14-0413-PAA-WS, issued August 14, 2014, in Docket No. 130153-WS, *In re: Application for staff-assisted rate case in Highlands County, by L.P. Utilities Corporation c/o LP Waterworks, Inc.*; Order No. PSC-15-0013-PAA-WS, issued January 2, 2015, in Docket No. 130194-WS, *In re: Application for staff-assisted rate case in Lake County by Lakeside Waterworks, Inc.*; Order No. PSC-15-0282-PAA-WS, issued July 8, 2015, in Docket No. 140158-WS, *In re: Application for increase in water/wastewater rates in Highlands County by HC Waterworks, Inc.*; Order No. PSC-15-0329-PAA-WU, issued August 14, 2015, in Docket No. 140186-WU, *In re: Application for staff-assisted rate case in Brevard County by Brevard Waterworks, Inc.*; Order No. PSC-15-0335-PAA-WS, issued August 20, 2015, in Docket No. 140147-WS, *In re: Application for staff-assisted rate case in Sumter County by Jumper Creek Utility Company.*

reasonable with the exception of some allocated expenses related to salary overtime, fuel, and vehicle maintenance which were adjusted in those dockets.[14]

Subsequent to the test year, USWSC increased Raintree's annual contract by $348 to reflect an increase in the Consumer Price Index (CPI).[15] USWSC previously adjusted Raintree's contract to remove the salary overtime allowance, but did not adjust the fuel and vehicle maintenance expenses at that time. USWSC subsequently determined that Raintree's actual test year fuel and vehicle maintenance expenses were $642 less than the amount allocated in the test year contract, or $652 less than the amount allocated in the current contract following the CPI adjustment. Consistent with the Commission's decisions related to Raintree's sister utilities, staff increased this account by $348 to annualize the increase in the monthly contract price. Staff also decreased this account by $652 to reflect Raintree's actual test year fuel and vehicle maintenance expenses including the CPI adjustment. Staff's net adjustment to this account is a decrease of $304 ($348 - $652 = -$304). The adjusted annual contract fee of $21,440 equals an average of $195 per equivalent residential connection (ERC), which is comparable to the amounts approved by the Commission for Raintree's sister utilities which ranged from $170 to $247 per water ERC.

The Utility confirmed that USWSC's current cost model continues to include 1,000 additional projected ERCs.[16] Inclusion of 1,000 potential future ERCs that are expected to be added through growth or acquisitions serves to spread the costs over a larger base and lowers the cost per ERC. Also, USWSC did not include any salary for the Manager of Regulated Utilities in the administrative services cost, which also serves to lower costs to customers.[17] In addition, USWSC's contract with Raintree uses a 14 percent margin for overhead and profit rather than the 18 percent markup previously used. As a result of including the additional ERCs and reducing the margin by 4 percent, Raintree receives an annual subsidy of $1,821 from USWSC. Staff also notes that Raintree's O&M expenses have decreased by more than $6,000 when compared to the Utility's last SARC in 2008. In addition to the $1,821 cost subsidy resulting from USWSC's cost model, Raintree is experiencing additional cost savings related to expenses such as chemicals, testing, and miscellaneous expenses that are attributable to economies of scale achieved through operations provided under the USWSC contract.

USWSC and its managers bring considerable management and operator experience and expertise at a comparably reasonable cost. By spreading costs over multiple systems, and adding ERCs to recognize potential future growth, Raintree's customers are realizing operational and cost benefits that would not be available if the Utility operated on a stand-alone basis. Staff believes the adjusted cost of the USWSC management services contract is reasonable. Therefore, staff recommends contractual services – other expense for the test year of $21,440.

[14]Order No. PSC-15-0282-PAA-WS; Order No. PSC-15-0329-PAA-WU; and Order No. PSC-15-0335-PAA-WS.
[15]Document No. 02483-16, filed on April 26, 2016, in Docket No. 150199-WU.
[16]Document No. 02483-16.
[17]Order No. PSC-15-0282-PAA-WS.

Insurance Expense (655)

The Utility recorded $835 in this account. During the test year, the Utility's general liability insurance policy was renewed at a higher premium. Staff increased this account by $479 to reflect the Utility's current annual general liability insurance expense of $1,314. Therefore, staff recommends insurance expense for the test year of $1,314.

Regulatory Commission Expense (665)

The Utility did not record any regulatory commission expense in this account. As discussed in Issue 3, staff reclassified the Utility's $750 certificate transfer application filing fee from plant to this expense account. Rule 25-30.433(8), F.A.C., requires that non-recurring expenses be amortized over a five-year period unless a shorter or longer period of time can be justified. Accordingly, staff increased this account by $150 to reflect the five-year amortization of the certificate transfer application filing fee ($750/5 = $150). The remaining unamortized portion of the filing fee should be recorded in Account No. 186 – Miscellaneous Deferred Debits.

Regarding the instant case, the Utility is required by Rule 25-22.0407, F.A.C., to provide notices of the customer meeting and notices of final rates in this case to its customers. For noticing, staff estimated $106 for postage expense, $77 for printing expense, and $11 for envelopes. This results in $194 for the noticing requirement. The Utility paid a $500 rate case filing fee. The Utility also requested additional rate case expense of $500 to cover travel expenses to attend both the customer meeting and Commission Agenda Conference. The Commission previously approved rate case related travel expenses ranging from $450 to $1,570 in the three most recent dockets for Raintree's sister utilities. Based on staff's review, the requested travel expense appears reasonable. Pursuant to Section 367.0816, F.S., rate case expense is amortized over a four-year period.[18] Based on the above, staff recommends total rate case expense of $1,194 ($194 + $500 + $500), which amortized over four years is $298. Based on the above, staff's total adjustment to this account is an increase of $448 ($150 + $298 = $448). Therefore, staff recommends regulatory commission expense of $448.

Bad Debt Expense (670)

Raintree recorded $568 in this account for test year bad debt expense. Commission practice is to calculate bad debt expense using a three-year average, however, three years of records are not yet available for the current owners who purchased Raintree on May 23, 2014. The Utility reported $234 in bad debt expense for June through December 2014.[19] Subsequent to the test year, Raintree reported $479 in bad debt expense for 2015, which equals 1.02 percent of staff's recommended revenue requirement.[20] Raintree indicated it is amenable to using $479 for the test year.[21] Staff believes the 2015 expense is more representative of Raintree's expected bad debt expense going forward, and provides a reasonable alternative to a traditional three-year average in this case. Therefore, staff has decreased this account by $89 ($479 - $568 = -$89), and recommends a test year bad debt expense of $479.

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[18]Section 367.0816, F.S., is still in effect at this time, but will be repealed effective July 1, 2016, pursuant to HB 491.

[19]Raintree Waterworks, Inc. 2014 Annual Report.

[20]Raintree Waterworks, Inc. 2015 Annual Report.

[21]Document No. 02483-16.

Miscellaneous Expense (675)

The Utility recorded $698 for miscellaneous expense. This account includes the Department of State's Division of Corporation's annual filing fee of $150, the DEP's drinking water annual operating license fee of $500, and several Sunshine State Florida One Call fees totaling $48. Staff decreased this account by $24 to remove the Sunshine State Florida One Call fees that occurred outside the test year. Staff recommends miscellaneous expense of $674 for the test year.

Operation and Maintenance Expense (O&M Summary)

Based on the above adjustments, O&M expense should be decreased by $584, resulting in total O&M expense of $33,402. Staff's recommended adjustments to O&M expense are shown on Schedule Nos. 3-A, 3-B, and 3-C.

Depreciation Expense (Net of Amortization of CIAC)

The Utility's records reflect test year depreciation of $10,875 and CIAC amortization of $1,280, for a net depreciation expense of $9,595 ($10,875 - $1,280 = $9,595). Staff calculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C., and determined depreciation expense to be $7,752. Also, staff determined that the pro forma flow meter replacement results in a minor incremental increase of $7 in depreciation expense. Accordingly, staff decreased this account by a net adjustment of $3,116 ($7,752 + 7 - $10,875 = -$3,116). Staff's decrease to depreciation expense is primarily due to the elimination of $3,123 in depreciation expense going forward for plant Account No. 320 – Water Treatment Equipment that became fully depreciated during the test year. In addition, staff calculated CIAC amortization based on composite rates, and determined that no adjustments are necessary. This results in a net depreciation expense of $6,479 ($7,752 + $7 - $1,280 = $6,479). Therefore, staff recommends net depreciation expense of $6,479.

Taxes Other Than Income (TOTI)

Raintree recorded TOTI of $2,951 for the test year. The Utility recorded $1,997 for regulatory assessment fees (RAFs). Based on staff's recommended test year revenues of $42,540, the Utility's RAFs should be $1,914. Therefore, staff decreased this account by $83 to reflect the appropriate RAFs. Also, the Utility recorded property tax accruals of $954 during the test year. Audit staff determined that the Utility's actual property taxes for the 2014 tax year were $671. However, subsequent to the audit, the 2015 property tax records became available, indicating that Raintree paid lower property taxes of $567 for the 2015 tax year. In addition, the pro forma flow meter replacement discussed in Issue 3 results in a minor $3 increase in the Utility's property taxes. Based on the 2015 property taxes plus the minor pro forma adjustment, staff decreased this account by $384 to reflect the appropriate property taxes going forward ($567 + $3 - $954 = -$384). Staff's total adjustment to test year TOTI is a decrease of $467 (-$83 - $384 = -$467).

In addition, as discussed in Issue 7, revenues have been increased by $4,510 to reflect the change in revenue required to cover expenses and allow the recommended rate of return. As a result, TOTI should be increased by $203 to reflect RAFs of 4.5 percent of the change in revenues. Therefore, staff recommends TOTI of $2,687.

Operating Expenses Summary

The application of staff's recommended adjustments to Raintree's test year operating expenses result in operating expenses of $42,568. Operating expenses are shown on Schedule No. 3-A. The adjustments are shown on Schedule No. 3-B.

Issue 7: What is the appropriate revenue requirement?

Recommendation: The appropriate revenue requirement is $47,050, resulting in an annual increase of $4,510 (10.60 percent). (Golden)

Staff Analysis: Raintree should be allowed an annual increase of $4,510 (10.60 percent). This will allow the Utility the opportunity to recover its expenses and earn an 8.74 percent return on its investment. The calculations are as follows in Table 7-1 below:

Table 7-1
Water Revenue Requirement

Adjusted Rate Base	$51,282
Rate of Return	x 8.74%
Return on Rate Base	$4,482
Adjusted O&M Expense	33,402
Depreciation Expense (Net)	6,479
Taxes Other Than Income	2,687
Income Taxes	0
Revenue Requirement	$47,050
Less Adjusted Test Year Revenues	42,540
Annual Increase	$4,510
Percent Increase	10.60%

Issue 8: What is the appropriate rate structure and rates for Raintree's water system?

Recommendation: The recommended rate structure and monthly water rates are shown on Schedule No. 4. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved rates should not be implemented until staff has approved the proposed customer notice and the notice has been received by the customers. The Utility should provide proof of the date notice was given within 10 days of the date of the notice. (Bruce)

Staff Analysis:

Water Rates

Raintree's service territory is located in the St. Johns River Water Management District (SJRWMD), which has water restrictions in place. The Utility provides water only service to 109 residential customers and one general service customer. The general service customer is the home owners' association and water is provided to irrigate the common areas. The billing data indicates that approximately 11 percent of the residential customer bills during the test year had zero gallons indicating a non-seasonal customer base. The average residential water demand is 10,029 gallons per month. Currently, the water system rate structure for residential customers consists of a base facility charge (BFC) and a two-tier inclining block rate structure. The rate blocks are: (1) 0-8,000 gallons per month, and (2) all usage in excess of 8,000 gallons per month. General service customers are billed based on a BFC and uniform gallonage charge.

Staff performed an analysis of the Utility's billing data in order to evaluate the appropriate rate structure for the residential water customers. The goal of the evaluation was to select the rate design parameters that: (1) produce the recommended revenue requirement; (2) equitably distribute cost recovery among the utility's customers; (3) establish the appropriate non-discretionary usage threshold for restricting repression; and (4) implement, where appropriate, water conserving rate structures consistent with Commission practice.

In this case, staff recommends that 40 percent of the water revenues should be generated from the BFC, which will provide sufficient revenues to design gallonage charges that send pricing signals to customers using above the non-discretionary level. The average people per household served by the water system is two; therefore, based on the number of people per household, 50 gallons per day per person, and the number of days per month, the non-discretionary usage threshold should be 3,000 gallons per month. Staff recommends a BFC and a three-tier inclining block rate structure, which includes separate gallonage charges for discretionary and non-discretionary usage for residential water customers. The rate blocks are: (1) 0-3,000 gallons; (2) 3,001-8,000 gallons; and (3) all usage in excess of 8,000 gallons per month. This rate structure sends the appropriate pricing signals because it targets customers with high consumption levels and minimizes price increases for customers at non-discretionary levels. In addition, the third tier provides an additional pricing signal to customers using in excess of 8,000 gallons of water per month, which includes approximately 52 percent of the demand. General service customers should be billed a BFC and uniform gallonage charge.

Based on a recommended revenue increase of 10.7 percent, which excludes $218 of miscellaneous revenues, the residential consumption can be expected to decline by 572,000 gallons resulting in anticipated average residential demand of 9,602 gallons per month. Staff recommends a 4.3 percent reduction in test year residential gallons for rate setting purposes and corresponding reductions of $182 for purchased power, $13 for chemicals, and $9 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $46,627. Table 8-1 below, contains staff's recommended rate structure and two alternative rate structures at another BFC allocation and tiers.

Table 8-1
Staff's Recommended and Alternative Water Rate Structures and Rates

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES	ALTERNATIVE I (40% BFC)	ALTERNATIVE II (40% BFC)
Residential		(40% BFC)		
5/8" x 3/4" Meter Size	$13.60	$13.79	$13.80	$13.79
Charge per 1,000 gallons				
0-8,000 gallons	$1.58			
Over 8,000 gallons	$1.96			
0-3,000 gallons		$1.66		
3,001-8,000 gallons		$1.76		
Over 8,000 gallons		$2.64		
0-3,000 gallons			$1.70	
3,001-10,000 gallons			$1.79	
Over 10,000 gallons			$2.69	
0-3,000 gallons				$2.09
Over 3,000 gallons				$2.22
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$18.34	$18.77	$18.90	$20.06
8,000 Gallons	$26.24	$27.57	$27.85	$31.16
10,000 Gallons	$30.16	$32.85	$31.43	$35.60

Source: Current tariff and staff's calculations

Summary

The recommended rate structure and rates are shown on Schedule No. 4. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved rates should not be implemented until staff has approved the proposed customer notice and the notice has been received by the customers. The Utility should provide proof of the date notice was given within 10 days of the date of the notice.

Issue 9: What is the appropriate amount by which rates should be reduced four years after the published effective date to reflect the removal of the amortized rate case expense as required by Section 367.0816, F.S?

Recommendation: The water rates should be reduced as shown on Schedule No. 4, to remove rate case expense grossed-up for RAFs and amortized over a four-year period. The decrease in rates should become effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.0816, F.S. The Utility should be required to file revised tariffs and a proposed customer notice setting forth the lower rates and the reason for the reduction no later than one month prior to the actual date of the required rate reduction. If Raintree files this reduction in conjunction with a price index or pass-through rate adjustment, separate data should be filed for the price index and/or pass-through increase or decrease and the reduction in the rates due to the amortized rate case expense. (Bruce, Golden)

Staff Analysis: Section 367.0816, F.S., requires that the rates be reduced immediately following the expiration of the four-year period by the amount of the rate case expense previously included in the rates.[22] The reduction will reflect the removal of revenues associated with the amortization of rate case expense, the associated return on working capital, and the gross-up for RAFs which is $316. Using the Utility's current revenues, expenses, and customer base, the reduction in revenues will result in the rate decrease shown on Schedule No. 4.

Raintree should be required to file revised tariff sheets no later than one month prior to the actual date of the required rate reduction. The Utility also should be required to file a proposed customer notice setting forth the lower rates and the reason for the reduction. If Raintree files this reduction in conjunction with a price index or pass-through rate adjustment, separate data should be filed for the price index and/or pass-through increase or decrease and the reduction in the rates due to the amortized rate case expense.

[22]Section 367.0816, F.S., is still in effect at this time, but will be repealed effective July 1, 2016, pursuant to HB 491.

Issue 10: What are the appropriate initial customer deposits for Raintree?

Recommendation: The appropriate water initial customer deposit should be $64 for the residential 5/8" x 3/4" meter size. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for water service. The approved initial customer deposits should be effective for connections made on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475, F.A.C. (Bruce)

Staff Analysis: Rule 25-30.311, F.A.C., contains the criteria for collecting, administering, and refunding customer deposits. Customer deposits are designed to minimize the exposure of bad debt expense for the Utility and ultimately, the general body of ratepayers. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill.[23] Currently, the Utility does not have initial customer deposits. Based on the staff recommended water rates and the post repression average residential demand, the appropriate initial customer deposit should be $64 for water to reflect an average residential customer bill for two months.

Staff recommends that the appropriate water initial customer deposit should be $64 for the residential 5/8" x 3/4" meter size. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for water service. The approved initial customer deposits should be effective for connections made on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475, F.A.C.

[23]Order Nos. PSC-13-0611-PAA-WS, issued November 19, 2013, in Docket No. 130010-WS, *In re: Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.* and PSC-14-0016-TRF-WU, issued January 6, 2014, in Docket No. 130251-WU, *In re: Application for approval of miscellaneous service charges in Pasco County, by Crestridge Utility Corporation.*

Issue 11: Should the recommended rates be approved for Raintree on a temporary basis, subject to refund, in the event of a protest filed by a party other than the Utility?

Recommendation: Yes. Pursuant to Section 367.0814(7), F.S., the recommended rates should be approved for the Utility on a temporary basis, subject to refund, in the event of a protest filed by a party other than the Utility. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. Prior to implementation of any temporary rates, the Utility should provide appropriate security. If the recommended rates are approved on a temporary basis, the rates collected by the Utility should be subject to the refund provisions discussed below in the staff analysis. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the Utility should file reports with the Commission Clerk's office no later than the 20th of every month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund. (Golden)

Staff Analysis: This recommendation proposes an increase in rates. A timely protest might delay what may be a justified rate increase resulting in an unrecoverable loss of revenue to the Utility. Therefore, pursuant to Section 367.0814(7), F.S., in the event of a protest filed by a party other than the Utility, staff recommends that the recommended rates be approved as temporary rates. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. The recommended rates collected by the Utility should be subject to the refund provisions discussed below.

The Utility should be authorized to collect the temporary rates upon staff's approval of an appropriate security for the potential refund and the proposed customer notice. Security should be in the form of a bond or letter of credit in the amount of $3,014. Alternatively, the Utility could establish an escrow agreement with an independent financial institution.

If the Utility chooses a bond as security, the bond should contain wording to the effect that it will be terminated only under the following conditions:

1. The Commission approves the rate increase; or,
2. If the Commission denies the increase, the Utility shall refund the amount collected that is attributable to the increase.

If the Utility chooses a letter of credit as a security, it should contain the following conditions:

1. The letter of credit is irrevocable for the period it is in effect; and
2. The letter of credit will be in effect until a final Commission order is rendered, either approving or denying the rate increase.

If security is provided through an escrow agreement, the following conditions should be part of the agreement:

1. The Commission Clerk, or his or her designee, must be a signatory to the escrow agreement.
2. No monies in the escrow account may be withdrawn by the Utility without the prior written authorization of the Commission Clerk, or his or her designee.
3. The escrow account shall be an interest bearing account.
4. If a refund to the customers is required, all interest earned by the escrow account shall be distributed to the customers.
5. If a refund to the customers is not required, the interest earned by the escrow account shall revert to the Utility.
6. All information on the escrow account shall be available from the holder of the escrow account to a Commission representative at all times.
7. The amount of revenue subject to refund shall be deposited in the escrow account within seven days of receipt.
8. This escrow account is established by the direction of the Florida Public Service Commission for the purpose(s) set forth in its order requiring such account. Pursuant to Cosentino v. Elson, 263 So. 2d 253 (Fla. 3d DCA 1972), escrow accounts are not subject to garnishments.
9. The account must specify by whom and on whose behalf such monies were paid.

In no instance should the maintenance and administrative costs associated with the refund be borne by the customers. These costs are the responsibility of, and should be borne by, the Utility. Irrespective of the form of security chosen by the Utility, an account of all monies received as a result of the rate increase should be maintained by the Utility. If a refund is ultimately required, it should be paid with interest calculated pursuant to Rule 25-30.360(4), F.A.C.

The Utility should maintain a record of the amount of the bond, and the amount of revenues that are subject to refund. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the Utility should file reports with the Commission Clerk's office no later than the 20th of every month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund.

Issue 12: Should Raintree be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision?

Recommendation: Yes. The Utility should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. Raintree should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA primary accounts as shown on Schedule No. 5 have been made to the Utility's books and records. In the event the Utility needs additional time to complete the adjustments, notice should be provided within seven days prior to the deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days. (Golden)

Staff Analysis: The Utility should be required to notify the Commission, in writing that it has adjusted its books in accordance with the Commission's decision. Schedule No. 5 reflects the accumulated plant, depreciation, CIAC, and amortization of CIAC balances as of July 31, 2015. Raintree should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA primary accounts, as shown on Schedule No. 5, have been made to the Utility's books and records. In the event the Utility needs additional time to complete the adjustments, notice should be provided within seven days prior to the deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days.

Issue 13: Should this docket be closed?

Recommendation: No. If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively. (Tan, Lherisson)

Staff Analysis: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively.

RAINTREE WATERWORKS, INC. | **SCHEDULE NO. 1-A**
TEST YEAR ENDED 7/31/15 | **DOCKET NO. 150199-WU**
SCHEDULE OF WATER RATE BASE

	DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTILITY BALANCE	BALANCE PER STAFF
1.	UTILITY PLANT IN SERVICE	$252,519	($518)	$252,001
2.	LAND & LAND RIGHTS	5,740	0	5,740
3.	NON-USED AND USEFUL COMPONENTS	0	0	0
4.	CIAC	(29,750)	0	(29,750)
5.	ACCUMULATED DEPRECIATION	(201,496)	6,109	(195,387)
6.	AMORTIZATION OF CIAC	15,143	(640)	14,503
7.	WORKING CAPITAL ALLOWANCE	0	4,175	4,175
8.	WATER RATE BASE	$42,156	$9,126	$51,282

RAINTREE WATERWORKS, INC.
TEST YEAR ENDED 7/31/15
ADJUSTMENTS TO RATE BASE

SCHEDULE NO. 1-B
DOCKET NO. 150199-WU

		WATER
	UTILITY PLANT IN SERVICE	
1.	To reclassify certificate transfer application filing fee from plant Acct. 302 to expense Acct. 665 - Regulatory Commission Expense.	($750)
2.	To reflect pro forma flow meter replacement for well #3 to Acct. 309.	$929
3.	To reflect retirement of replaced flow meter for well #3 to Acct. 309.	($697)
	Total	($518)
	ACCUMULATED DEPRECIATION	
1.	To reflect pro forma retirement of replaced flow meter on well #3.	$697
2.	To reflect pro forma accumulated depreciation per Rule 25-30.140, F.A.C.	($7)
3.	To reflect an averaging adjustment.	$5,419
	Total	$6,109
	AMORTIZATION OF CIAC	
	To reflect an averaging adjustment.	($640)
	WORKING CAPITAL ALLOWANCE	
	To reflect 1/8 of test year O&M expenses.	$4,175

RAINTREE WATERWORKS, INC.
TEST YEAR ENDED 7/31/15
SCHEDULE OF CAPITAL STRUCTURE

SCHEDULE NO. 2
DOCKET NO. 150199-WU

	CAPITAL COMPONENT	PER UTILITY	SPECIFIC ADJUST-MENTS	BALANCE BEFORE RECONCILE TO RATE BASE	ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON STOCK	$0	$0	$0					
2.	RETAINED EARNINGS	0	0	0					
3.	PAID IN CAPITAL	0	0	0					
4.	OTHER COMMON EQUITY	49,929	0	49,929					
	TOTAL COMMON EQUITY	$49,929	$0	$49,929	$1,353	$51,282	100.00%	8.74%	8.74%
5.	LONG TERM DEBT	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%
6.	SHORT-TERM DEBT	0	0	0	0	0	0.00%	0.00%	0.00%
7.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
	TOTAL DEBT	$0	$0	$0	$0	$0	0.00%		
8.	CUSTOMER DEPOSITS	$0	$0	$0	$0	$0	0.00%	2.00%	0.00%
9.	TOTAL	$49,929	$0	$49,929	$1,353	$51,282	100.00%		8.74%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	7.74%	9.74%
OVERALL RATE OF RETURN	7.74%	9.74%

RAINTREE WATERWORKS, INC.
TEST YEAR ENDED 7/31/15
SCHEDULE OF WATER OPERATING INCOME

SCHEDULE NO. 3-A
DOCKET NO. 150199-WU

		TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1.	**OPERATING REVENUES**	$40,670	$1,870	$42,540	$4,510	$47,050
					10.60%	
	OPERATING EXPENSES:					
2.	OPERATION & MAINTENANCE	$33,985	($584)	$33,402	$0	$33,402
3.	DEPRECIATION (NET)	9,595	(3,116)	6,479	0	6,479
4.	TAXES OTHER THAN INCOME	2,951	(467)	2,484	203	2,687
5.	INCOME TAXES	0	0	0	0	0
6.	**TOTAL OPERATING EXPENSES**	$46,531	($4,166)	$42,365	$203	$42,568
7.	**OPERATING INCOME/(LOSS)**	($5,861)		$175		$4,482
8.	**WATER RATE BASE**	$42,156		$51,282		$51,282
9.	**RATE OF RETURN**	(13.90%)		0.34%		8.74%

RAINTREE WATERWORKS, INC.
TEST YEAR ENDED 7/31/15
ADJUSTMENTS TO OPERATING INCOME

SCHEDULE NO. 3-B
DOCKET NO. 150199-WU

		WATER
	OPERATING REVENUES	
1.	To reflect test year revenues.	$1,662
2.	To reflect miscellaneous revenues.	208
	Subtotal	$1,870
	OPERATION AND MAINTENANCE EXPENSES	
1.	Purchased Power (615)	
	To reflect 8.5% excessive unaccounted for water adjustment.	($399)
2.	Chemicals (618)	
	To reflect 8.5% excessive unaccounted for water adjustment.	($29)
3.	Contractual Services - Professional (631)	
	To reflect appropriate accounting services expense.	($667)
4.	Contractual Services - Other (636)	
	a. To reflect appropriate contractual services – other expense.	$348
	b. To reflect appropriate fuel and vehicle maintenance expense.	(652)
	Subtotal	($304)
5.	Insurance Expense (655)	
	To reflect appropriate general liability insurance expense.	$479
6.	Regulatory Commission Expense (665)	
	a. To reflect 5-year amortization of transfer filing fee reclassified from plant Acct. 302.	$150
	b. To reflect 4-year amortization of rate case expense ($1,194/4).	298
	Subtotal	$448
7.	Bad Debt Expense (670)	
	To reflect appropriate bad debt expense.	($89)
8.	Miscellaneous Expense (675)	
	To remove Sunshine State One Call of Florida fees outside the test year.	($24)
	TOTAL OPERATION & MAINTENANCE ADJUSTMENTS	($584)
	DEPRECIATION EXPENSE	
	To reflect appropriate depreciation calculated per Rule 25-30.140, F.A.C.	($3,116)
	TAXES OTHER THAN INCOME	
1.	To reflect appropriate test year RAFs.	($83)
2.	To reflect appropriate Utility property taxes.	(384)
	Total	($467)

RAINTREE WATERWORKS, INC. TEST YEAR ENDED 7/31/15 ANALYSIS OF WATER OPERATION AND MAINTENANCE EXPENSE			SCHEDULE NO. 3-C DOCKET NO. 150199-WU
	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(601) SALARIES AND WAGES - EMPLOYEES	$0	$0	$0
(603) SALARIES AND WAGES - OFFICERS	3,000	0	3,000
(604) EMPLOYEE PENSIONS AND BENEFITS	0	0	0
(610) PURCHASED WATER	0	0	0
(615) PURCHASED POWER	4,689	(399)	4,290
(616) FUEL FOR POWER PRODUCTION	0	0	0
(618) CHEMICALS	345	(29)	316
(620) MATERIALS AND SUPPLIES	0	0	0
(630) CONTRACTUAL SERVICES - BILLING	0	0	0
(631) CONTRACTUAL SERVICES - PROFESSIONAL	2,107	(667)	1,440
(635) CONTRACTUAL SERVICES - TESTING	0	0	0
(636) CONTRACTUAL SERVICES - OTHER	21,744	(304)	21,440
(640) RENTS	0	0	0
(650) TRANSPORTATION EXPENSE	0	0	0
(655) INSURANCE EXPENSE	835	479	1,314
(665) REGULATORY COMMISSION EXPENSE	0	448	448
(670) BAD DEBT EXPENSE	568	(89)	479
(675) MISCELLANEOUS EXPENSE	698	(24)	674
	$33,985	($584)	$33,402

RAINTREE WATERWORKS, INC. — **SCHEDULE NO. 4**
TEST YEAR ENDED 7/31/2015 — **DOCKET NO. 150199-WU**
MONTHLY WATER RATES

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential and General Service			
Base Facility Charge by Meter Size			
5/8" x 3/4"	$13.60	$13.79	$0.09
3/4"	$20.41	$20.69	$0.14
1"	$34.02	$34.48	$0.23
1-1/2"	$68.03	$68.95	$0.47
2"	$108.85	$110.32	$0.75
3"	$217.69	$220.64	$1.49
4"	$340.14	$344.75	$2.33
6"	$680.30	$689.50	$4.66
Charge per 1,000 Gallons- Residential			
0-8,000 gallons	$1.58		
Over 8,000 gallons	$1.96		
0-3,000 gallons		$1.66	$0.01
3,001-8,000 gallons		$1.76	$0.01
Over 8,000 gallons		$2.64	$0.02
Charge per 1,000 gallons - General Service	$1.79	$2.17	$0.01
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
3,000 Gallons	$18.34	$18.77	
8,000 Gallons	$26.24	$27.57	
10,000 Gallons	$30.16	$32.85	

RAINTREE WATERWORKS, INC. **SCHEDULE NO. 5**
TEST YEAR ENDED 7/31/2015 **DOCKET NO. 150199-WU**
SCHEDULE OF WATER PLANT, DEPRECIATION, CIAC, & CIAC AMORTIZATION BALANCES

ACCT NO.	DEPR. RATE PER RULE 25-30.140, F.A.C.	DESCRIPTION	UPIS 7/31/2015 (DEBIT)	ACCUM. DEPR. 7/31/2015 (CREDIT)*
301	2.50%	ORGANIZATION	$2,587	$199
302	2.50%	FRANCHISES	0	0
303	0.00%	LAND AND LAND RIGHTS (NON-DEPRECIABLE)	5,740	0
304	3.70%	STRUCTURES AND IMPROVEMENTS	13,979	7,908
307	3.70%	WELLS AND SPRINGS	24,733	18,663
309	3.13%	SUPPLY MAINS	4,179	2,957
311	5.88%	PUMPING EQUIPMENT	40,241	35,908
320	5.88%	WATER TREATMENT EQUIPMENT	53,968	53,968
330	3.03%	DISTRIBUTION RESERVOIRS AND STANDPIPES	11,448	9,741
331	2.63%	TRANSMISSION AND DISTRIBUTION MAINS	62,668	46,309
333	2.86%	SERVICES	11,580	9,291
334	5.88%	METERS AND METER INSTALLATIONS	1,268	155
335	2.50%	HYDRANTS	12,879	9,041
336	10.00%	BACKFLOW PREVENTION DEVICES	6,500	2,899
340	6.67%	OFFICE FURNITURE AND EQUIPMENT	5,739	4,458
		TOTAL INCLUDING LAND	$257,509	$201,496
			CIAC AMORT. 7/31/2015 (DEBIT)*	**CIAC 7/31/2015 (CREDIT)**
			$15,143	$29,750

* The plant and accumulated depreciation balances exclude the pro forma flow meter replacement. Also, the accumulated depreciation and accumulated amortization of CIAC balances exclude the staff-recommended averaging adjustments that are used only for rate setting purposes and should not be reflected on the Utility's books.

Item 10

FILED MAY 26, 2016
DOCUMENT NO. 03218-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

RECEIVED-FPSC
2016 MAY 26 AM 11:05
COMMISSION CLERK

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Higgins, Wu)
Division of Accounting and Finance (Archer, Buys, Yeazel)
Office of the General Counsel (Mapp)

RE: Docket No. 150265-EI – Petition for approval of 2015 nuclear decommissioning study, by Florida Power & Light Company.

AGENDA: 06/09/16 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Edgar

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On December 14, 2015, Florida Power & Light Company (FPL or company) filed its 2015 Nuclear Decommissioning Cost Study (2015 study or current study) for Plant Turkey Point Units 3 and 4 (TP3 and TP4) and Plant St. Lucie Units 1 and 2 (SL1 and SL2). Rule 25-6.04365, Florida Administrative Code (F.A.C.), requires any utility under Florida Public Service Commission (Commission) jurisdiction that owns a nuclear generating unit to file a site-specific decommissioning cost study at least once every five years. The purpose of periodic decommissioning reviews is to recognize developments affecting decommissioning cost estimates, and to also consider such factors as additional information, improvements in technology, and regulatory changes that have transpired since the last decommissioning study. Staff has reviewed the company's current study and presents its recommendation herein.

Nuclear Decommissioning

Decommissioning involves the physical dismantling and removing of plant buildings, materials, and equipment that are no longer used and useful but remain following retirement of the nuclear generating unit. With respect to the funding of decommissioning activities, the Nuclear Regulatory Commission's (NRC) final rule, 10 C.F.R. Section 50.75, requires that licensees provide reasonable financial assurance that funds will be available for decommissioning through prepayment prior to the start of operation, an external sinking fund or a surety method, insurance, or other guarantee method. An external sinking fund is defined as:

> A fund established and maintained by setting funds aside periodically in an account segregated from licensee assets and outside the administrative control of the licensee and its subsidiaries or affiliates in which the total amount of funds would be sufficient to pay decommissioning costs at the time permanent termination of operations is expected. An external sinking fund may be in the form of a trust, escrow account, or Government fund, with payment by certificate of deposit, deposit of Government or other securities.

FPL's funding program has historically provided for financial assurance through monthly contributions to its nuclear decommissioning trust (NDT) funds. As discussed later, the company's currently authorized monthly/annual base rate decommissioning contribution (Accrual) is set at zero dollars per month/year.[1] Thus, financial assurance standards are being satisfied solely by fund growth since 2005. FPL's decommissioning funds are held externally with The Bank of New York Mellon, which serves as fund trustee, with numerous financial management firms governing asset investments.[2] FPL's external sinking fund complies with the NRC's final rule because reasonable financial assurance is provided that funds will be available for the future decommissioning of its nuclear units.[3]

The Commission approved the external sinking funding method by Order No. 21928.[4] In determining the annual provision for decommissioning, the current cost estimate is escalated to the expected dates of actual decommissioning. The escalation rate used is determined by using a combination of general economic inflation rates and inflation rates for decommissioning labor, transportation, and burial of nuclear waste. Once the escalated decommissioning cost is known, a sinking fund annuity is calculated to determine the annual annuity. This annual annuity plus the earnings on the NDT fund, net of taxes, will grow to the escalated cost of decommissioning.

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[1] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company; and Docket No. 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 FPL Settlement)

[2] Responses to Staff's First Data Request No. 68.

[3] Responses to Staff's First Data Request Nos. 56, 57, 58, and 74.

[4] Order No. 21928, issued September 29, 1989, in Docket No. 870098-EI, In re: Petitions for approval of an increase in the accrual of nuclear decommissioning costs by Florida Power Corporation and Florida Power & Light Company. On June 20, 2001, Florida Power Corporation was acquired by Carolina Power & Light Company and became Progress Energy Florida, Inc., effective January 1, 2003. On April 29, 2013, Progress Energy Florida, Inc. officially changed its name to Duke Energy Florida, Inc. (d/b/a Duke Energy Florida) following its merger with Duke Energy. On September 15, 2015, the Commission acknowledged Duke Energy Florida, Inc.'s name change to Duke Energy Florida, LLC.

The primary objective of a NDT fund is to have enough money on hand at the time of decommissioning to meet all required expenses at the lowest possible cost to utility ratepayers. No set of investment policies will meet this goal with certainty. The management of the fund, therefore, must be concerned with both the preservation of contributions and the purchasing power of the contributions. To this end, the Commission, by Order No. 21928, required that the fund's assets earn a consistent positive real return over a market cycle.[5] The imposed minimum fund earnings rate is at least the rate of inflation measured by the Consumer Price Index (CPI) over each five-year review period.

First appearing in FPL's 1994 Nuclear Decommissioning Cost Study (1994 study) were considerations for the treatment of spent fuel generated during the operation of its nuclear units.[6] While the storage and disposal of spent nuclear fuel (SNF) assemblies (high-level waste) generated during plant operations were not considered a decommissioning expense, the presence of SNF on-site does impact the cost of decommissioning. Faced with the uncertainties of the Department of Energy (DOE) meeting its 1998 deadline for the acceptance of SNF, the Commission recognized that SNF may have to remain on-site long after decommissioning begins. For this reason, an allowance for on-site dry storage costs was made in determining decommissioning accruals for each nuclear unit. The primary goal in requiring an on-site dry storage allowance was to ensure that the funds needed to fully decommission FPL's nuclear units are available when the plants retire, while being recovered from customers who received nuclear generated energy. The Commission found that these costs should continue to be reviewed to determine the prudence of their inclusion in decommissioning accruals. Staff notes that FPL's 2015 study does include provisions for on-site SNF management, which are further discussed in Issue 1.

End of Life Materials and Supplies and Last Core of Nuclear Fuel

In the review of FPL's 1998 Nuclear Decommissioning Cost Study (1998 study), the Commission addressed, for the first time, recovery of nuclear materials and supplies (M&S) costs,[7] as well as the costs of unburned nuclear fuel (Last Core)[8] expected to remain at the end of each generating unit's life (EOL). The Commission found that these costs are unique to the nuclear unit and are the direct result of unit shut down.[9] However, the Commission recognized that these costs do not meet the intent of nuclear decommissioning because they do not involve

[5] Id.

[6] Order No. PSC-95-1531-FOF-EI, issued December 12, 1995, in Docket No. 941350-EI, In re: Petition for increase in annual accrual for Turkey Point and St. Lucie nuclear unit decommissioning costs by Florida Power & Light Company; and Docket No. 941352-EI, In Re: Petition for Approval of Increase In Accrual for Nuclear Decommissioning Costs by Florida Power Corporation.

[7] EOL M&S inventories are the level of unique inventories that will remain at the end of each nuclear site's life (license expiration of the last nuclear unit at the site).

[8] The Last Core is the unburned fuel that will remain in the fuel assemblies at the end of the last operating cycle of each nuclear unit when it ceases operation.

[9] Order No. PSC-02-0055-PAA-EI, issued January 7, 2002, in Docket No. 981246-EI, In re: Petition by Florida Power & Light Company for approval of annual accrual for Turkey Point and St. Lucie nuclear decommissioning unit costs; Docket No. 990324-EI, In re: Disposition of Florida Power & Light Company's accumulated amortization pursuant to Order PSC-96-0461-FOF-EI; and Docket No. 991931-EG, In re: Determination of appropriate method of recovery for the last core of nuclear fuel for Florida Power & Light Company and Florida Power Corporation.

the removal of plant facilities. The Commission concluded that the costs associated with EOL M&S inventories and Last Core should be amortized over the remaining life span[10] of each unit. The Commission found that amortizing EOL M&S and Last Core costs over the remaining life span of each plant ratably allocates the costs to customers receiving nuclear generated power.

The Commission further ordered that the amortization of costs associated with EOL M&S inventories be accounted for as a debit to nuclear maintenance expense with a credit to an unfunded Account 228 reserve. For costs associated with the Last Core, the Commission ordered that the amortization should be recorded as a base rate fuel expense with a credit to an unfunded Account 228 reserve.[11] The Commission also found that the costs associated with EOL M&S and the Last Core should be addressed in subsequent decommissioning studies so that the related annual amortization expenses could be revised, if warranted. Staff notes FPL has provided updates for its respective EOL M&S and Last Core costs in the current study. These updated costs and amortizations are further discussed in Issues 3 and 4.

Recent Decommissioning Orders Pertaining to FPL

By Order No. PSC-05-0902-S-EI, issued September 14, 2005, the Commission approved a Settlement Agreement that suspended FPL's then annual nuclear decommissioning accrual.[12] Per the terms of the Stipulation and Settlement, FPL was to file a decommissioning study (2005 study) on or before December 31, 2005, and the results of the study would have no impact on customer rates for the term of the Settlement. FPL's annual base rate nuclear decommissioning accrual (which is exclusive of EOL M&S and Last Core amortization expenses) has remained at zero dollars per year from 2005 forward.

FPL's last decommissioning proceeding, in accordance with Rule 25-6.04365, F.A.C., occurred in 2010. The company's cost analysis and continuation of a zero annual accrual was approved by Order No. PSC-11-0381-PAA-EI.[13] Generally speaking, FPL's current study is similar to its 2010 Decommissioning Study (2010 study or prior study) both in terms of the general scope of decommissioning and plant inventory levels. Staff notes that additional plant inventories resulting from FPL's Extended Power Uprate Project were initially accounted for as part of the 2010 study.[14]

The Commission is vested with jurisdiction over these matters through several provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06.

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[10] Remaining life span for each nuclear unit is that period of years from the decommissioning study date to the nuclear license expiration date.
[11] Order No. PSC-02-0055-PAA-EI.
[12] Order No. PSC-05-0902-S-EI.
[13] Order No. PSC-11-0381-PAA-EI, issued September 12, 2011, in Docket No. 100458-EI, In re: Petition for approval of 2010 nuclear decommissioning study, by Florida Power & Light Company.
[14] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, in Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plants, for exemption from Bid Rule 25-22.082, Florida Administrative Code (F.A.C.), and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.

Discussion of Issues

Issue 1: What are the current total estimated costs to decommission Florida Power and Light Company's Turkey Point Nuclear Units 3 and 4, and St. Lucie Nuclear Units 1 and 2, valued in 2015 dollars terms?

Recommendation: Staff recommends the Commission find that the total current estimated cost valued in 2015 dollars for decommissioning Turkey Point Nuclear Units 3 and 4 is $1,777,304,990, and $1,806,479,491 for St. Lucie Nuclear Units 1 and 2. (Higgins)

Staff Analysis: In accord with Rule 25-6.04365, F.A.C., FPL filed an updated site-specific decommissioning cost study on December 14, 2015. The purpose of this study is to recognize developments and changes impacting decommissioning cost estimates of the company's nuclear units, and to also consider such factors as additional information, improvements in technology, and regulatory changes that have transpired since FPL's last nuclear decommissioning study and review in 2010.

Operating License

FPL's Turkey Point Nuclear Generating Station (Turkey Point) began service in 1972 with the commissioning of Unit No. 3, while Unit No. 4 achieved operational status one year later in 1973. The St. Lucie Nuclear Power Plant (St. Lucie) began service in 1976 with Unit 1, while Unit 2 began service approximately seven years later in 1983. All four units were originally licensed by the NRC to operate for a maximum of forty years. From 2000-2001, FPL filed applications with the NRC for twenty-year operating license extensions for all four units. In 2002, the NRC approved FPL's license extension request for TP3 and TP4, while approving extensions for SL1 and SL2 in 2003. Accordingly, all four units' investment amounts will continue to be included in rate base until expiration of their respective extended operating licenses/retirement. The operating license expiration dates for TP3 and TP4 are July 2032 and April 2033, respectively. The operating license expiration dates for SL1 and SL2 are March 2036 and April 2043, respectively. The current cost study assumes that each unit will operate throughout its extended license period.

Decommissioning Methods

The NRC accepts the following three decommissioning methods: prompt removal/dismantling (DECON), mothballing with delayed dismantling (SAFSTOR), and entombment (ENTOMB). Consistent with the 2010 study, the current study continues to utilize a combination of DECON and SAFSTOR decommissioning methods. FPL selected DECON for the Turkey Point units because this method provides the lowest cost and employs those individuals familiar with the nuclear facility to support the dismantling effort. Further, DECON eliminates a potential long-term safety hazard and relieves the company of the long-term obligation and liability for continuing maintenance of the property. For the St. Lucie units, due to the timing difference in operating license expiration dates, SAFSTOR is utilized for SL1 with an approximate seven-year dormancy period, followed by prompt dismantlement (DECON) of both SL1 and SL2 concurrently. This allows for a one-time mobilization of contractor personnel and equipment by mothballing SL1 until the expiration of SL2's license.

The company currently projects SNF to remain at each plant site after the majority of nuclear facilities have been removed. Staff notes that in order for a nuclear plant to be considered fully-decommissioned, no on-site SNF may be present. The company is projecting that the final fuel assemblies will be removed from Turkey Point by 2072, and by 2073 for St. Lucie.

Towards the end of the decommissioning process, or at least two years prior to the expected license termination dates of approximately 2072 for Turkey Point, and 2073 for St. Lucie, FPL is required to submit to the NRC a License Termination Plan (LTP). Once the physical decommissioning process (including removal of SNF and storage facilities) is complete, the NRC will determine if site remediation has been performed in accordance with the LTP; and if envisioned by the LTP, the site will be released (by the NRC) for unrestricted use.[15] Staff notes that FPL's current decommissioning study assumes site remediation to the level of unrestricted use.[16] At this point, the nuclear license will be terminated thus concluding NRC oversight.

Decommissioning Cost Estimates

The major decommissioning cost drivers/centers in FPL's 2015 study are: program management (staffing/labor), high and low-level radioactive waste management and disposal, site security, and removal-related activities (engineering, demolition, and support equipment). Consequently, these cost drivers also reflect the greatest dollar value changes from the 2010 study. These specific cost drivers are discussed individually further in staff's recommendation.

As with previous decommissioning cost studies, FPL commissioned TLG Services Inc. (TLG) to develop its current decommissioning cost estimates. The cost estimates are based on a number of assumptions, including regulatory requirements, low-level waste disposal practices, high-level radioactive waste management options, project contingencies, and site restoration requirements. The estimates include a five and one-half year cooling period (in fuel pool) for the SNF when plant operations cease and the reactors are permanently de-fueled. Once cooled, the SNF will be transferred to an on-site independent spent fuel storage installation (ISFSI) for interim storage. The decommissioning cost estimates include the dismantling of facilities, site structures, ISFSI, and site restoration.

TLG utilizes a unit factor method for estimating decommissioning activity costs.[17] These factors incorporate site-specific costs, the most current worker productivity in decommissioning

[15] U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Radiological Criteria for License Termination," Federal Register, Volume 62, Number 139, July 21, 1997.

[16] Responses to Staff's Second Data Request No. 2.

[17] The unit factor method of estimating costs is based on activity-dependent costs (i.e., costs to decontaminate and remove components for disposal), period-dependent costs (e.g., management staff for the duration of the program), and collateral costs (e.g., insurance and taxes). These costs include labor, equipment, materials, energy, and services. In addition, the effect of salvage and scrap values and contingencies are incorporated into the estimate. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) are developed using local labor rates. The activity-dependent costs are estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Each activity, such as cutting pipe, segmenting vessels, demolishing concrete, transporting and disposing of wastes, is individually cost estimated. The unit factors are expressed in terms of the cost per cut, cost per cubic foot demolished, cost per trip, or cost per cubic yard of burial. The unit cost factors are applied to the inventory of plant equipment and structures to be removed from each nuclear unit to develop a cost estimate.

activities, and lessons learned from other decommissioning projects. Unit factors for concrete removal, steel removal, and cutting costs were developed and valued using local labor rates. The activity-dependent costs were estimated with item quantities developed from plant drawings and inventory documents. Staff notes that unit factors are not used for non-repetitive tasks, such as removal of a steam generator or segmentation of the reactor pressure vessel. For estimating equipment, consumable, and sorbent costs, the company relied upon information published by R.S. Means[18] (adjusted for the geographic/regional locations of the nuclear plants), and McMaster-Carr.[19]

The total estimated cost to decommission Turkey Point has increased by approximately 28.2 percent from the 2010 study.[20] The total estimated costs to decommission St. Lucie increased by 22.2 percent during the same timeframe. Tables presenting the cost comparisons by major category using the selected methods of decommissioning from 2010 to 2015 are presented below. Staff notes that the two vintages of cost figures shown below are unadjusted (nominal) and presented as they were in the year of study, or 2010 dollars and 2015 dollars, respectively.

Table 1-1
Turkey Point Decommissioning Cost Comparison 2010-2015

Plant Turkey Point Units 3 and 4	2010 Study ($1000s)	2015 Study ($1000s)	Percent Difference	Annual Percent Difference
License Termination	932,988	1,204,251	29.1	5.2
Spent Fuel Management	374,006	478,765	28.0	5.1
Site Restoration	79,223	94,289	19.0	3.5
Total*	1,386,216	1,777,305	28.2	5.1

Source: FPL's 2010 and 2015 Decommissioning Studies

Table 1-2
St. Lucie Decommissioning Cost Comparison 2010-2015

Plant St. Lucie Units 1 and 2	2010 Study ($1000s)	2015 Study ($1000s)	Percent Difference	Annual Percent Difference
License Termination	1,052,235	1,208,237	14.8	2.8
Spent Fuel Management	331,105	486,705	47.0	8.0
Site Restoration	95,414	111,537	16.9	3.2
Total*	1,478,754	1,806,479	22.2	4.1

Source: FPL's 2010 and 2015 Decommissioning Studies
*May not add due to rounding

On an individual unit basis, the current estimated costs in 2015 dollars for the decommissioning of FPL's nuclear plants are as follows: TP3 equals $844,719,728, TP4 equals $932,585,262, SL1

[18] Robert Snow Means Company, Inc., "Building Construction Cost Data 2015," Kingston, Massachusetts.
[19] www.mcmaster.com online catalog, McMaster Carr Spill Control.
[20] Please refer to FPL's response to Staff's Second Data Request, No. 6, for the most current decommissioning cost figures for Turkey Point Units 3 and 4, which staff references throughout this recommendation.

equals \$934,648,631, and SL2 equals \$871,830,860. Staff notes that due to SL2 being jointly-owned with the Orlando Utilities Commission and Florida Municipal Power Agency (Joint Owners), FPL is responsible for approximately 85.1percent of the unit's total decommissioning cost. The joint owners fund the remaining amount. Staff further notes that the joint owners maintain separate (from FPL) external sinking funds for satisfying both their decommissioning cost obligations and the NRC's financial assurance rule. The funding level status of the joint owners' NDTs as of December 31, 2014 are sufficiently above the NRC's required minimum.[21]

As discussed above, all costs are ultimately classified as those relating to the activities of License Termination, Spent Fuel Management, or Site Restoration. However, these major cost classifications are comprised of individual cost elements. Below, staff analyzes estimated cost variances between FPL's current and 2010 study by these individual elements.

Program Management

Program management is the largest single element of the overall decommissioning cost estimate. The program management cost element primarily captures costs relating to the staffing (both plant personnel and contractors) and organization during the decommissioning process. This includes overall project oversight as well as management of day-to-day activities. Program management costs increased by approximately 17.1 percent, or \$83.7 million for Turkey Point, and 14.0 percent, or \$69.2 million for St. Lucie from the company's prior study in 2010. Primarily driving the higher costs are general increases in wages and benefits over the five-year study period.

Security

Due to insight gained from recent and active decommissioning projects, for example the decommissioning of Vermont Yankee, TLG adjusted its cost model to increase the number of on-site security personnel throughout the decommissioning process. The current study assumes that a 24-hour security organization will be present with possible modifications made as the decommissioning process progresses (i.e. reduced security forces once all SNF has been removed from the plant sites). Security costs increased by approximately \$91.9 million, or 65.9 percent for Turkey Point, and by \$71.2 million, or by 64.6 percent for St. Lucie. As well as the increased number of onsite personnel, a general increase in wages and benefits also contributed to the higher cost of security.

Spent Fuel Management (Direct Expenditures)[22]

The Nuclear Waste Policy Act of 1982 (NWPA) committed the DOE to accept and dispose of SNF and high-level radioactive waste (HLRW). The acceptance and disposal of SNF and HLRW by the DOE was to begin by January 31, 1998, as stipulated under its Standard Disposal Contract with waste generators. With respect to a final SNF repository, the DOE submitted its license application to the NRC on June 3, 2008, seeking authorization to construct a storage facility located at Yucca Mountain, Nevada. The NRC formally docketed the DOE's license application on September 8, 2008, triggering a three-year deadline, with a possible one-year extension, set

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[21] Responses to Staff's First Data Request No. 60.

[22] Direct spent fuel management expenditures excludes program management costs but includes costs for dry shielded storage canisters and horizontal storage modules, spent fuel loading/transfer/spent fuel pool O&M fees.

by Congress for the NRC to decide whether to authorize construction. The application review was suspended in 2011, which generated legal action in the United States Federal Court of Appeals. In August 2013, the US Court of Appeals for the District of Columbia Circuit issued a Writ of Mandamus ordering the NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application.[23] As part of its resumed review, the NRC has now issued all volumes of its formal Safety Evaluation Report (SER) of the project.[24] Staff notes that further actions and formal proceedings must occur before a licensing decision can be made and that substantial uncertainty remains as to the operational prospects of the Yucca Mountain repository.

Separate and apart from the Yucca Mountain project and NRC reviews, the DOE has "begun implementing a consent-based siting process to establish an integrated waste management system to transport, store, and dispose of commercial spent nuclear fuel and high level defense radioactive waste."[25] Staff understands the purpose of this policy direction and approach, which is in an early and investigative state, is to ultimately establish a number of high-level nuclear waste sites specializing in specific classes of waste. However, to date, no national final repository has been identified and fully licensed to receive commercial SNF.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all spent fuel at the reactor site until title of the fuel is transferred to the DOE.[26] Accordingly, FPL has incorporated costs relating to the storage and management of SNF generated at the Turkey Point and St. Lucie sites into its current study. However due to the non-performance by the DOE of terms contained in the Standard Disposal Contract with FPL, litigation was brought by the company. Ultimately, in 2009, FPL entered into a settlement agreement with the federal government for damages incurred relating to SNF storage and management.[27] As part of the settlement agreement, the company receives annual payments to cover the costs incurred for managing and storing SNF that it would otherwise not have incurred if the original terms of its Standard Disposal Contract with the DOE had been met. FPL is currently projecting that SNF management costs incurred before years 2059 at Turkey Point and 2063 at St. Lucie, are eligible for reimbursement. Staff notes that the company's expenditures for storing and managing SNF that have already been reimbursed by the federal government through 2014 equal $233,328,195.[28]

[23] 725 F.3d 255 (D.C. Cir. 2013) IN RE: AIKEN COUNTY, ET AL., PETITIONERS, STATE OF NEVADA, INTERVENOR

[24] The NRC's Yucca Mountain Repository SER details the evaluation the DOE's license application for a construction authorization. The NRC staff issued its SER in five volumes. The five SER Volumes document the NRC staff's review of the general information (SER Volume 1), repository safety before permanent closure (Volume 2), repository safety after permanent closure (Volume 3), administrative and programmatic requirements (Volume 4), and proposed conditions on the construction authorization and probable subjects of license specifications (Volume 5).

[25] "Invitation for Public Comment To Inform the Design of a Consent-Based Siting Process for Nuclear Waste Storage and Disposal Facilities; Notice of Invitation for Public Comment," 80 Federal Register 246 (23 December 2015), pp. 79874 – 79874.

[26] U.S. Code of Federal Regulations, Title 10, Part 50 – Domestic Licensing of Production and Utilization Facilities, Subpart 54 (bb), "Conditions of Licenses".

[27] Responses to Staff's First Data Request, No. 77.

[28] Responses to Staff's First Data Request, No. 1.

For the purposes of the current study, FPL assumes a DOE repository for disposing of commercial SNF will be operational and available in 2030. This date assumes a decision to select a repository site is made within the next two to four years, five years to complete licensing, and eight years for construction. Assumptions relating to FPL's spent fuel management plan in its current decommissioning study include: (1) 2031 Turkey Point and 2032 St. Lucie start dates for transfer of SNF to a federal facility; (2) pickup based on the oldest fuel receiving priority by the DOE; and (3) a maximum acceptance capacity of 3,000 metric tons of uranium per year at a geologic repository. Accounting for the aforementioned assumptions, transfer of all SNF from Turkey Point to the DOE would be completed by the end of 2072. Transfer of all SNF from St. Lucie to the DOE would be completed by 2073.

Total estimated direct costs for spent fuel management increased 32 percent, or $69.7 million, for Turkey Point and 30 percent, or $65.4 million, for St. Lucie from FPL's prior study. The increase is primarily due to the current cost estimate containing more comprehensive assumptions for contractor mobilization, physical transfer of SNF to the DOE, and performing required survey and safety validations.

Low-level radioactive waste disposal

The contaminated and activated material generated in the decontamination and dismantling of a nuclear reactor is classified as low-level radioactive waste (LLRW). LLRWs are classified based on levels of radioactivity (lowest-to-highest) as either Class A, B, C, or Greater than Class C (GTCC). Staff notes the majority of LLRW assumed for disposal in FPL's analysis, in terms of both volume and mass, is Class A waste.

For LLRW disposal cost estimation and planning purposes, the company has a Life of Plant Agreement with Energy*Solutions* (Energy Solutions) to dispose of Class A nuclear waste at Energy Solutions' facility in Clive, Utah. Energy Solutions' facility does not have a license to dispose of Class B or C radioactive waste, which is more highly radioactive than Class A. For purposes of the current cost estimate, disposal costs for Class A waste are based on FPL's agreement with Energy Solutions.

On November 10, 2011, Waste Control Specialists (WCS) opened the Texas Low-Level Radioactive Waste Disposal Compact Facility in Andrews County, Texas. This facility is licensed to dispose of Class A, B, and C low-level radioactive wastes. For purposes of FPL's 2015 study, Classes B and C waste are assumed to be shipped and disposed of at the WCS facility with costs based upon published rates for non-Texas Compact generators.[29] The current cost estimate also assumes that certain amounts of radioactive metallic material will be conditioned and processed as to allow for non-controlled disposal. Metal conditioning is assumed to be performed by Energy Solutions in Oak Ridge, Tennessee.

[29] Current members of the Texas Compact include Texas and Vermont, however; non-compact states or waste generators can enter into contractual agreements with the Texas Low-Level Radioactive Waste Disposal Compact Commission to dispose of nuclear waste in Texas.

The total estimated cost of low-level radioactive waste disposal increased 32 percent for Turkey Point, and 15 percent for St. Lucie, or by $37.6 and $23.1 million respectively, from FPL's 2010 study. The increase is primarily due to shifting the cost basis for disposing of Class B and Class C waste from the previously assumed Barnwell Low-Level Radioactive Waste Disposal Facility in South Carolina to the WCS facility in Texas. [30]

The greater estimated cost increase at Turkey Point relative to St. Lucie was due to the addition of 5,220 cubic yards of contaminated soil/earthen material at Turkey Point. This specific soil was generated from past projects at Turkey Point and had not been accounted for in prior studies due to the material's low level of radioisotopes. However, FPL elected to utilize this material as engineering fill in the construction of a Low-Level Waste Storage Facility expansion/laydown area. The company claims that for conservatism, the soil along with the waste storage facility, were added to the scope of the Turkey Point decommissioning cost estimate.[31]

Removal

Removal costs primarily capture costs related to the disassembly of plant components and placed in a central area or zone for processing/disposal, controlled removal of contaminated and activated concrete, remediation of any hazardous waste, excavation of soil, and demolition of site structures. Removal costs increased by approximately 21.8 percent, or $32.6 million for Turkey Point, and 18.1 percent, or $33.1 million for St. Lucie from the company's prior study in 2010. Approximately half of the increase in projected removal costs are attributed to changes in heavy equipment assumed necessary to complete the decommissioning projects.

Contingency Allowance

The practice of budgeting a cost contingency allowance is common in large-scale construction and demolition projects. Such project cost estimates generally include a baseline cost estimate, which is formulated based on ideal conditions, and a contingency allowance. A contingency allowance is a specific provision for unforeseeable elements and associated costs within the defined project scope. For large, complex, and long-running projects such as nuclear plant decommissioning, unforeseeable events are likely to occur; therefore, a contingency allowance is necessary.

For each of FPL's four nuclear units, TLG applied specific contingency allowances to the individual units' decommissioning cost estimates on a line item basis to produce a weighted average contingency value. These specific line item contingency allowances are based on guidelines developed by the Atomic Industrial Forum (now Nuclear Energy Institute) in its report "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036. Dividing the sum (dollar value) of the line item contingency allowances by the total decommissioning cost for each unit respectively results in the company's proposed weighted average contingency percentages. The contingency values for all four nuclear units have marginally increased from FPL's prior study as displayed in the table below:

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[30] Beginning in 2008, the Barnwell Low-Level Radioactive Waste Disposal Facility, operated by Energy*Solutions*, only accepts waste from the Atlantic compact states (Connecticut, New Jersey, and South Carolina).

[31] Responses to Staff's First Data Request No. 23, 30, 37, and Responses to Staff's Second Data Request No. 5.

Table 1-3
Weighted Average Contingency Factors

Nuclear Unit	2010 Study[32]	2015 Study
TP3	17.39%	17.46%
TP4	17.36%	17.41%
SL1	17.07%	17.37%
SL2	17.92%	18.04%

Source: FPL's 2010 and 2015 Decommissioning Studies

Staff believes the contingency provisions presented in FPL's 2015 decommissioning study, which are based on industry standards and guidelines, as discussed above are reasonable.[33]

Site Characterization and License Termination Surveys

Characterization and site survey cost estimates have increased substantially from the prior study.[34] Site characterization and survey costs increased 107.4 percent, or $19.3 million, at Turkey Point, and 77.9 percent, or $18.9 million at St. Lucie. The primary driver of the cost increase is the inclusion of new remedial action surveys that were not included in the 2010 study for either nuclear plant. Other elements include increased labor and material costs.

Other Factors

Transportation, regulatory fees, and energy cost estimates have increased since the 2010 cost study. The increase in transportation cost estimates are due to a combination of higher tariffs, fuel surcharges and a greater amount of assumed shipments. Costs for insurance (Nuclear Liability and Nuclear Property insurance), Emergency Planning Fees, Nuclear License Fees, and NRC reviews and inspections fees have all increased since the 2010 study. Partially mitigating the overall increase in decommissioning costs are lower costs for off-site waste processing (cost of conditioning metals/material for non-LLRW disposal). The reduction in off-site waste processing costs is due to reduced contractual rates with Energy Solutions for this service.

Conclusion

Staff believes the company, in estimating current decommissioning costs for Turkey Point and St. Lucie as discussed above, appropriately recognized and reflected factors including new/updated information, improvements in technology, and regulatory changes that have transpired during the last five years. Thus, based on information contained in FPL's 2015 Decommissioning Study and associated data request responses, staff recommends the Commission find that the total current estimated cost valued in 2015 dollars for decommissioning TP 3 and TP4 is $1,777,304,990, and $1,806,479,491 for SL1 and SL2.

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[32] Order No. PSC-11-0381-PAA-EI.

[33] Responses to Staff's First Data Request No. 48 and Responses to Staff's First Request for Documents No. 1.

[34] Decommissioning Characterization refers to the process of obtaining and analyzing information relating the types, quantities, and chemical /physical states of radionuclides that will affect the decommissioning process.

Issue 2: What are the appropriate annual accruals, in equal dollar amounts, necessary to recover the future decommissioning costs of Florida Power and Light's Turkey Point Nuclear Units 3 and 4, and St. Lucie Nuclear Units 1 and 2?

Recommendation: Staff recommends a continuation of the suspension of the accrual for nuclear decommissioning as approved by the Commission in Order No. PSC-11-0381-PAA-EI. The appropriate jurisdictional annual accrual amount necessary to recover future decommissioning costs over the remaining life of each nuclear power plant is currently zero. Additionally, staff recommends the assumptions included in FPL's 2015 decommissioning study to determine the annual accrual are reasonable. (Archer, D. Buys, Yeazel)

Staff Analysis: The annual accrual amounts recommended by staff are based upon information provided by FPL in its site-specific cost study and in its responses to staff's data requests. The base level costs included in the study are in 2015 dollars. Once the cost of decommissioning a nuclear unit is determined in current dollars, this cost is escalated to future dollars. The determination of the annual accrual amounts then resembles an annuity calculation. The question becomes how much money needs to be collected from customers in equal monthly payments, earning at a given rate, to equal decommissioning costs in future dollars at a future date. The appropriate escalation rates and fund earnings rate will be discussed in detail later in this issue.

To qualify for tax deductibility of contributions made to a qualified decommissioning fund, the amounts must be consistent with the purpose of IRC Section 468A, the principles and provisions of Federal Tax Regulations under the Code section, and be based on reasonable assumptions.[35] The company can generally satisfy its burden of proof by demonstrating that the amounts are calculated based on the assumptions used by the Commission in its most recent order.[36] The Commission's order must be based on reasonable assumptions concerning: (i) the after tax rate of return to be earned by the amounts collected for decommissioning; (ii) the total estimated cost of decommissioning the nuclear power plant; and (iii) the frequency of contributions to the nuclear decommissioning fund for a tax year.[37] Staff believes the assumptions proposed by FPL are reasonable, and therefore, should be deemed appropriate for establishing amounts in the nuclear decommissioning study. FPL's annual accruals and contributions to FPL's qualified and non-qualified trust funds were suspended in 2005, and FPL's 2015 Decommissioning Study confirms that the trust continues to be adequately funded without additional accruals. Therefore, a specific ruling to allow FPL to obtain IRS approval pursuant to IRC Section 468A is not required in this docket.

Base Costs of Decommissioning

FPL provided the estimated cost in current (December 31, 2015) dollars to decommission each of its nuclear units. The estimated cost to decommission each nuclear unit is shown in Table 2-1.

[35] 26 USC §468A (2011), and Treas. Reg. §1.468A.
[36] Treas. Reg. §1.468A-3(a)(4).
[37] Treas. Reg. §1.468A-3(a)(2).

Table 2-1
Decommission Costs per Plant

Nuclear Unit	2015 Dollars
TP3	844,720,000
TP4	932,585,000
SL1	934,649,000
SL2	871,831,000
Total	3,583,785,000

Source: FPL's 2015 Decommissioning Study

FPL divides the analysis performed for the decommissioning process into five general components. The components are labor, materials, transportation, burial, and other. TLG provided FPL with estimates of the base costs for each activity. These cost estimates were determined through site-specific cost studies and include a contingency allowance. The cost studies reflect weighted average contingency allowances of 17.46 percent for TP3, 17.41 percent for TP4, 17.37 percent for SL1, and 18.04 percent for SL2.

According to FPL, the primary reasons for the net increase in decommissioning costs from 2010 to 2015 are due to actual data ascertained from recent ongoing decommissioning experience in the industry. The largest increases of costs were in security, program management, and spent fuel management. FPL indicated that it has no evidence to suggest that the rate of increase experienced over the last five years would continue prospectively, but instead, believes that these increases are due to the heightened level of current decommissioning activity which has significantly expanded its knowledge base regarding actual costs for certain specific activities compared to what was known in 2010.

Cost Escalation Rates

The next issue that must be addressed is the determination of the appropriate escalation rates to use to convert the current decommissioning cost to the future decommissioning cost for each nuclear unit. The analysis performed by FPL divides the decommissioning process into five major cost components. These stages are labor, materials and equipment, shipping, burial, and other. The base level costs are in 2015 dollars. The 2015 current dollar estimates are escalated to future dollar estimates at the respective license termination date for each nuclear unit using separate inflation forecasts for the major cost components. FPL relied upon "The U.S. Economy, The 30-Year Outlook, August 2015," published by Global Insight as the source for their specific inflation measures, except for the burial escalation rate. FPL's burial cost escalation is based on company-specific data/historical experience and CPI.

The methodology used by FPL in the 2015 decommissioning study to determine the assumed escalation rates is consistent with the methodology used in the 2010 study. While FPL used a methodology consistent with the 2010 decommissioning cost study, the escalation rates do differ. The differences between the escalation rates used in the prior decommissioning study can be attributed to the change in the projections of the rates of inflation. The indicated escalation rate used to convert the current decommissioning cost to a future decommissioning cost for each nuclear unit is included in Table 2-2.

Table 2-2
Escalation Rate Comparison

Nuclear Unit	2010 Study	2015 Study[38]
TP3	2.95%	3.23%
TP4	2.95%	3.20%
SL1	2.84%	3.11%
SL2	2.97%	3.21%

Source: FPL's 2010 and 2015 Decommissioning Studies

Future Cost to Decommission

FPL's estimate of the total cost to decommission each nuclear unit in future dollars was based on present operating license termination dates, the current dollar base costs to decommission each nuclear unit as provided by TLG's site-specific study, the contingency allowances, and the escalation rates. The estimated costs in future dollars to decommission each nuclear unit at its respective license termination date are listed in Table 2-3.

Table 2-3
Future Cost to Decommission 2015 Study

Nuclear Unit	Dollars
TP3	1,909,345,000
TP4	2,125,111,000
SL1	2,556,058,000
SL2	2,552,581,000
Total	9,143,095,000

Source: Responses to Staff's Second Data Request, No. 6.

Funding Period

The funding period is that period over which revenues are collected from ratepayers for purposes of decommissioning the nuclear units. Funding periods are assumed to expire on the last day of the month preceding the month in which the operating license for the unit is due to expire. The operating license expiration dates for the nuclear units are listed in Table 2-4.

[38] Staff notes that FPL's 2015 Decommissioning Study points out that the funding status is highly dependent upon the assumed escalation rates, which are currently assumed to be at near all-time lows, and could increase significantly in the future.

Table 2-4
NRC Operating License Expiration Dates

Nuclear Unit	Expiration Date
TP3	July 19, 2032
TP4	April 10, 2033
SL1	March 1, 2036
SL2	April 6, 2043

Source: FPL's 2015 Decommissioning Study

Years of Fund Expenditures

The years in which the accumulated decommissioning funds will be expended are listed in Table 2-5.

Table 2-5
Years of Fund Expenditures

Nuclear Unit	Period
TP3	2032-2073
TP4	2033-2073
SL1	2036-2074
SL2	2043-2074

Source: FPL's 2015 Decommissioning Study

Fund Earnings Rate

The fund earnings rate is an important assumption in the determination of the appropriate annual accrual amount. The amount of the annual accrual moves inversely to the fund earnings rate. In other words, the higher the assumed fund earnings rate, the lower the indicated annual accrual and vice versa. In its 2015 study, FPL used an assumed fund earnings rate of 3.7 percent for all four of its nuclear units. FPL's assumed rate is based on the CPI rate of 2.4 percent, plus a projected real long-term, after tax and net of fees, earnings rate (or spread) of 1.3 percent.

This is the same approach FPL used in the 2005 and 2010 decommissioning studies where the assumed earnings rate is compared to the CPI to assure that the overall return remains above CPI to maintain the purchase power of the accruals until actual decommissioning. In FPL's 2005 decommissioning study, in which the Commission took no action due to a settlement between Office of Public Counsel (OPC) and the company, FPL used an assumed fund earnings rate of 5.0 percent (CPI of 2.6 percent plus a spread of 2.4 percent). In FPL's 2010 study, the assumed fund earnings rate was 3.9 percent (CPI of 2.0 percent plus a spread of 1.9 percent). FPL explained that the lower rate in the 2015 study is due to softened post-recession long-term return expectations in light of uncertainty in the sustainability of long-term global economic growth and a lower base of interest rates. This assumption is based on an estimate of the expected nominal return of 3.7 percent over the life of FPL's nuclear decommissioning trust (NDT) fund.

The decrease in the long-term fund earnings rate reaffirms the importance of maintaining adequate funding and the value of the periodic review of these studies as required by Rule 25-

6.04365, F.A.C. The assumed fund earnings rate of 3.7 percent compared to a CPI of 2.4 percent reflects the projection of continued adequacy of the funds. This projection assumes an investment strategy where the funds are moved from an initial mix of 40 percent equities, 48.5 percent fixed income and 11.5 percent alternatives to one that reduces exposure to alternative strategies by the end of 2025. From 2026 to 2055 the NDT will consist of 100 percent fixed income and from 2056 to 2074 the fund will consist of 50 percent fixed income and 50 percent cash.

As demonstrated by the range of earned returns shown in Table 2-6, total fund returns have experienced some volatility from year to year. However, since 2010, the NDT has increased 5.1 percent, and since inception, the overall return has remained above CPI. FPL has projected long-term CPI at 2.4 percent, and based on the actual returns since inception, staff believes FPL's forecasted fund earnings rate of 3.7 percent is reasonable for the purpose of determining the appropriate annual accrual amount.

Table 2-6
NDT Time Weighted Returns

FPL	Fund Return	CPI	Spread
1 Year	-1.1%	0.9%	-0.2%
2 Years	3.0%	0.8%	2.2%
3 Years	6.1%	1.0%	5.1%
5 Years	6.2%	1.6%	4.6%
10 Years	5.0%	1.9%	3.1%
Inception	6.8%	2.7%	4.1%

Source: Responses to Staff's First Data Request, No. 53.

The fundamental purpose of the Commission's review of the decommissioning study is to make sure there will be adequate funding on hand at the time the nuclear units are decommissioned. The assumed fund earnings rate should be conservative enough to avoid a situation whereby future customers are burdened by inadequate funding for decommissioning. However, an assumed fund earnings rate that is too conservative inappropriately burdens current customers with expenses to be incurred in the future. As such, a certain amount of judgment is necessary to determine a fair balance between generations of customers.

For the reasons outlined above, staff believes FPL's assumed fund earnings rate of 3.7 percent is reasonable and should be used in the determination of the annual accrual amounts.

Minimum Fund Earnings Rate

Separate from the issue of the assumed fund earnings rate is the issue of whether the Commission should impose a minimum fund earnings rate. In Order No. 21928, the Commission determined that a minimum fund earnings rate equivalent to the level of inflation over each five-year review period would be appropriate.[39] The Commission reaffirmed this approach in the 1994 and 1998 FPL Nuclear Decommissioning Studies. In those orders[40] the Commission stated:

> Rather than attempting to set a prospective minimum fund earnings rate which may or may not be reasonable under future economic conditions, we will require that the companies set aside funds sufficient to meet the Commission's best estimate of the decommissioning liability and require the companies to maintain the purchasing power as well as the principal amount of these contributions. The companies' investment performance will be evaluated along with all other decommissioning activities every five years. If it is found that the companies' investment earnings, net of taxes and all other administrative costs charged to the trust fund, did not meet or exceed the CPI average for the period, then we will consider ordering the utility to cover this shortfall with additional monies to keep the trust fund whole with respect to inflation. We therefore find a minimum fund earnings rate equivalent to the level of inflation over each five-year review period would be appropriate.

FPL believes a minimum funds earnings rate should not be imposed and the current approach, as approved by the Commission, should remain in effect. The company explained that economic and financial market conditions can vary widely over time and are difficult, if not impossible, to predict. FPL also indicated that it is reasonable that the company be accountable for taking appropriate steps intended to preserve the principal value and the purchasing power of contributions collected from its customers. Staff concurs with FPL and believes this approach is reasonable and recommends that it remain in effect.

Conclusion

The current annual expense accrual requirements for FPL's nuclear unit decommissioning costs presented in the 2015 FPL Nuclear Decommission Study support a zero accrual and funding requirement as of December 31, 2015. Based on the current dollar cost to decommission each nuclear unit as determined in TLG's site-specific study, the unit-specific escalation rates recommended above, and the assumed fund earnings rates of 3.7 percent, staff believes FPL's request to continue the suspension of the accrual is reasonable.

Consistent with prior Commission practice and Rule 25-6.04365, F.A.C., the assumptions presented in FPL's nuclear decommissioning study should be reviewed and updated as appropriate at least once every five years, which may change the accrual requirement prospectively.

As such, staff recommends a continuation of the suspension of the accrual for nuclear decommissioning as approved by the Commission in Order No. PSC-11-0381-PAA-EI. Accordingly, the appropriate jurisdictional annual accrual amounts necessary to recover future decommissioning costs over the remaining life of each nuclear power plant are currently zero.

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[39] Order No. 21298.
[40] Order No. PSC-95-1531-FOF-EI and Order No. PSC-02-0055-PAA-EI.

Additionally, staff recommends that the assumptions included in FPL's 2015 decommissioning study to determine the annual accrual are reasonable.

Issue 3: Should the amortization expense associated with the unrecovered value of End-of-Life Materials and Supplies inventories that will exist at the nuclear site following shut down be revised?

Recommendation: Yes. Staff recommends that the Commission recognize the revised annual amortization expense associated with End-of-Life Materials and Supplies inventories for FPL of $1.973 million (system), based on the proposed January 1, 2017 effective date of new customer rates in the company's current rate case proceeding, Docket No. 160021-EI. FPL should address the amortization of End-of-Life Materials and Supplies inventories in its subsequent decommissioning studies so the related annual accruals can be revised, if warranted. (Wu)

Staff Analysis: The end of life materials and supplies (EOL M&S) inventories of a nuclear powered electrical plant consist of spare replacement parts and supplies[41] needing to be kept in inventory to ensure safe and reliable operations of the nuclear plant. These inventories are unique and will have little value other than scrap when the associated nuclear units are decommissioned. Recognized that a level of EOL M&S inventories will remain at the end of life of each nuclear plant, the Commission authorized FPL to amortize the cost of unrecovered EOL M&S inventories over the remaining life span of each nuclear plant to ratably allocate costs to those receiving the benefit of the nuclear fuel generated electric power.[42] Further, the Commission required FPL, for administrative ease, to address the amortization status of EOL M&S inventories in the company's subsequent updated nuclear decommissioning cost studies so the related annual amortization expense could be revised, if necessary.

In accordance with Order No. PSC-02-0055-PAA-EI, effective May 2002, FPL began recording the annual amortization expense associated with the EOL M&S inventories as a debit to nuclear maintenance expense with a credit to an unfunded Account 228 reserve. FPL's current level of annual amortization expense was required in its 2010 study and approved by the Commission with Order No. PSC-11-0381-PAA-EI. Because the Commission previously found that the recovery of the costs associated with the EOL M&S inventories should be considered as a base rate component,[43] it ordered that changes in amortization of the EOL M&S inventory-related expenses shall be considered in conjunction with changes in other base rate costs and revenue requirement determinations at the time of FPL's base rate proceeding. Consequently, FPL's authorized annual amortization determined in its 2010 study became effective in January 2013, consistent with the Stipulation and Settlement Agreement approved by the Commission with Order No. PSC-13-0023-S-EI.

In a decommissioning study, a company's required EOL M&S-related annual amortization is determined by dividing the remaining net unrecovered cost associated with the EOL M&S inventories by the remaining amortization period. The remaining net unrecovered cost is the difference between the estimated cost of EOL M&S inventories and the actual reserve balance

[41] EOL M&S inventories include assets such as spare pumps and subassemblies, motors, control modules, circuit boards, switch gear, circuit breakers, valves and valve parts, ventilation parts and filters, radiation monitoring parts, and similar types of equipment.
[42] Order No. PSC-02-0055-PAA-EI and Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.
[43] Order No. PSC-02-0055-PAA-EI.

accrued at a point in time. The remaining amortization period is usually assumed to be from the considered point in time to the end of operating license of the last nuclear unit at a nuclear site. In its 2015 study, FPL estimated the remaining net unrecovered cost associated with the EOL M&S inventories, as of December 31, 2015, to be approximately $19.13 million at St. Lucie (SL)[44] and $21.51 million at Turkey Point (TP).

In its 2015 decommissioning study, FPL proposed that any change in amortization accruals relating to EOL M&S inventories should be addressed in FPL's next base rate proceeding. Thus, the company updated its analysis associated with the EOL M&S inventories to align with the effective date of FPL's 2016 base rate case.[45] FPL's estimate of remaining net unrecovered cost of EOL M&S inventories, as of January 1, 2017, is approximately $18.66 million at SL and $20.57 million at TP. The resulting EOL M&S annual amortization expense is estimated to be $1.97 million ($0.71 million for SL and $1.26 million for TP), an increase of approximately $0.57 million annually from the current level. Details of the estimated EOL M&S inventories, reserve balances, remaining amounts to be recovered, and annual amortization amounts, as of January 1, 2017, are presented in Table 3-1.

Table 3-1
EOL M&S-Associated Amortization Expenses
($1000s)

Plant Unit	EOL M&S Inventories as of 1/1/2017	Reserve Balance as of 1/1/2017	Remaining Amounts to be Recovered	Current Amortization	Revised Amortization	Change in Amortization[46]
TP4*	36,435	15,865	20,570	938	1,263	325
SL2**	24,892	6,228	18,664	470	710	240
Total	61,327	22,093	39,234	1,408	1,973	565

Notes: * TP4 is the last unit to be decommissioned at Turkey Point nuclear site.
** SL2 is the last unit to be decommissioned at St. Lucie nuclear site.

Data Source: FPL's responses to Staff's First Data Request, No. 46; FPL's Responses to Staff's Second Data Request, No. 6; FPL 2015 Decommissioning Study, Assumptions and Schedule E; and Order No. PSC-11-0381-PAA-EI, Pages 19-20.

Based on review of information contained in FPL's 2015 Decommissioning Study and associated data request responses as well as prior Commission orders, staff believes that the revised amortization amounts presented in Table 3-1 are appropriate. Staff also believes that the updated EOL M&S amortization, $1.973 million, should be addressed in conjunction with changes in other base rate costs and revenue requirement determinations in FPL's current base rate proceeding, Docket No. 160021-EI.

[44] For 2015 Decommissioning Study, FPL's ownership share at the St. Lucie units is, 92.552245 percent, net of participants.
[45] FPL' Response to Staff's First Data request, No. 46.
[46] FPL's responses to Staff's First Data Request, No. 46; FPL's Responses to Staff's Second Data Request, No. 6; FPL 2015 Decommissioning Study, Assumptions and Schedule E; and Order No. PSC-11-0381-PAA-EI.

Conclusion

Staff recommends that the Commission approve the revised annual amortization expense associated with EOL M&S inventories for FPL of $1.973 million (system), effective with the date of new customer rates in FPL's current rate case proceeding, Docket No. 160021-EI. This represents an increase of approximately $0.57 million over the 2010 authorized amortization amount. The amortization of EOL M&S inventories should be included in subsequent decommissioning studies so the related annual accruals can be revised, if warranted.

Issue 4: Should the amortization expense associated with the cost of the Last Core of nuclear fuel be revised?

Recommendation: Yes. Staff recommends that the Commission recognize the revised annual amortization expense associated with the cost of the Last Core of nuclear fuel at FPL nuclear units of $11.073 million (system), based on the proposed January 1, 2017, effective date of new customer rates in FPL's current rate case proceeding, Docket No. 160021-EI. FPL should address the costs associated with the Last Core in subsequent decommissioning studies so the related annual accruals can be revised, if warranted. (Wu)

Staff Analysis: Last Core is the unburned nuclear fuel that will remain in the fuel assemblies at the end of the last operating cycle of each nuclear unit when it ceases operation. According to FPL, no feasible solution currently exists to allow the company to burn all the nuclear fuel by the time each nuclear unit ceases operation, or, to move the unburned fuel remaining at any nuclear unit at the time of unit shutdown to another unit.[47] Recognizing that the Last Core is associated with the final shut down of a nuclear unit and equates to an unrecovered cost at the end of each nuclear unit's life, the Commission authorized FPL to amortize the cost of the Last Core over the remaining life span of each nuclear unit to ratably allocate costs to those receiving the benefit of the nuclear generated power.[48] Further, the Commission required FPL, for administrative ease, to address the amortization status of the Last Core expense in the company's subsequent updated nuclear decommissioning cost studies so the related annual amortization expense could be revised, if necessary.

In accordance with Order No. PSC-02-0055-PAA-EI, effective May 2002, FPL began recording the annual amortization expense associated with the Last Core as a debit to nuclear maintenance expense with a credit to an unfunded Account 228 reserve. Similar to its EOL M&S, FPL's current level of annual amortization expense was required in its 2010 study and approved by the Commission with Order No. PSC-11-0381-PAA-EI. Because the Commission previously found that the recovery of the cost associated with the Last Core should be considered as a base rate component,[49] it ordered that changes in amortization of the Last Core-related expense shall be considered in conjunction with changes in other base rate costs and revenue requirement determinations at the time of FPL's base rate proceeding. Consequently, FPL's authorized annual amortization determined in its 2010 study became effective in January 2013, consistent with the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-13-0023-S-EI.

In a decommissioning study, a company's required Last Core-related annual amortization is determined by dividing the difference between the estimated EOL value of the Last Core of nuclear fuel and the cumulative amortization balance at a point in time, by the remaining amortization period which is usually assumed to be at the end of operating license of the nuclear unit. In its 2015 study, FPL estimated the remaining net unrecovered cost associated with each

[47] FPL's Responses to Staff's First Data Request, No. 48.
[48] Order No. PSC-02-0055-PAA-EI, Order No. PSC-05-0902-S-EI, Order No. PSC-11-0381-PAA-EI, and Order No. PSC-13-0023-S-EI.
[49] Order No. PSC-02-0055-PAA-EI.

nuclear unit at both of its St. Lucie and Turkey Point nuclear plants, as of December 31, 2015, resulting in a total of approximately $229.3 million.

In its 2015 decommissioning study, FPL proposed that any change in amortization accruals relating to the Last Core expense should be addressed in FPL's next base rate proceeding. Thus, the company updated its analysis associated with its EOL nuclear fuel-related expense to align with the effective date of FPL's 2016 base rate case.[50] FPL's estimate of remaining net unrecovered cost associated with the Last Core, as of January 1, 2017, is approximately $217.6 million in total. The resulting annual amortization expense is estimated to be $11.1 million, a decrease of $0.7 million annually from the current level. Details of the estimated Last Core-related costs, reserve balances, remaining amounts to be recovered, and annual amortization amounts, as of January 1, 2017, are presented in Table 4-1.

Table 4-1
Last Core-Associated Amortization Expenses
($1000s)

Plant Unit	Last Core Costs as of 1/1/2017	Reserve Balance as of 1/1/2017	Remaining Amounts to be Recovered	Current Amortization	Revised Amortization	Change in Amortization[51]
TP3	67,500	28,093	39,407	3,032	2,536	(496)
TP4	62,700	24,165	38,535	3,117	2,365	(752)
SL1	89,300	27,841	61,459	2, 933	3,200	267
SL2	98,700	20,550	78,150	2,672	2,972	300
Total	318,200	100,649	217,551	11,754	11,073	(681)

Data Source: FPL's responses to Staff's First Data Request, No. 52; FPL's Responses to Staff's Second Data Request, No. 6; FPL 2015 Decommissioning Study, Schedule F; and Order No. PSC-11-0381-PAA-EI, Pages 21-22.

Based on review of information contained in FPL's 2015 Decommissioning Study and associated data request responses as well as prior Commission orders, staff believes that the revised amortization amounts presented in Table 4-1 are appropriate. Staff also believes that the updated Last Core amortization, $11.073 million, should be addressed in conjunction with changes in other base rate costs and revenue requirement determinations in FPL's current base rate proceeding, Docket No. 160021-EI.

Conclusion

Staff recommends that the Commission approve the revised annual amortization expense associated with the cost of the Last Core for FPL of $11.073 million (system), effective with the date of new customer rates in FPL's current rate case proceeding, Docket No. 160021-EI. This represents a decrease of approximately $0.68 million from the 2010 authorized amortization

[50] FPL' Response to Staff's First Data Request, No. 52.
[51] FPL's responses to Staff's First Data Request, No. 52; FPL's Responses to Staff's Second Data Request, No. 6; FPL 2015 Decommissioning Study, Schedule F; and Order No. PSC-11-0381-PAA-EI.

amount. The amortization of the Last Core-related costs should be included in subsequent decommissioning studies so the related annual accruals can be revised, if warranted.

Issue 5: What should be the effective date for adjusting the annual decommissioning accrual amounts for TP3, TP4, SL1, SL2, amortization of nuclear EOL M&S inventories, and amortization of the costs associated with the Last Core?

Recommendation: If the staff recommendations in Issues 1 and 2 are approved, there is no change to the current approved zero decommissioning accrual. Therefore, an effective date for adjusting the annual decommissioning accrual is moot. If the staff recommendations in Issues 3 and 4 are approved, the revised annual amortization amounts relating to EOL M&S inventories (Issue 3) and the Last Core (Issue 4) should be effective at the time new base rates are approved. (Higgins, Wu)

Staff Analysis: By Order No. PSC-11-0381-PAA-EI, issued September 12, 2011, Petition for approval of 2010 nuclear decommissioning study, by Florida Power & Light Company, the Commission found that FPL's currently-approved zero annual decommissioning accrual did not warrant revision at that time. A review of FPL's 2015 study indicates that while decommissioning base cost estimates have increased since 2010, assumptions relating to escalation rates and trust fund earnings, as discussed in Issue 2, suggest that FPL's currently approved zero annual decommissioning accrual does not require revision at this time.

As previously discussed in Issues 3 and 4, FPL's current decommissioning study indicates revisions to the amortization of nuclear EOL M&S inventories and amortization of the costs associated with the Last Core are warranted. FPL's position and request is that any change in accrual amounts should be addressed in its next base rate proceeding. Staff notes the Commission is currently reviewing FPL's base rates in Docket No. 160021-EI. Given that the Commission found in the 1998 FPL Nuclear Decommissioning Study review that the amortization expenses associated with the Last Core and EOL M&S should be considered base rate obligations, staff agrees with the company's assessment.[52]

Conclusion

If the staff recommendations in Issues 1 and 2 are approved, there should be no change to the currently-approved zero annual decommissioning accrual. Therefore, the Commission need not establish an effective date at this time. If the staff recommendations in Issues 3 and 4 are approved, the revised annual amortization amounts relating to EOL M&S inventories and the Last Core should be effective at the time new base rates are approved.

[52] Order No. PSC-02-0055-PAA-EI.

Issue 6: When should FPL file its next nuclear decommissioning study?

Recommendation: FPL's next decommissioning cost study for the Turkey Point Nuclear Generating Station and the St. Lucie Nuclear Power Plant should be filed no later than December 14, 2020. (Higgins)

Staff Analysis: Rule 25-6.04365, F.A.C., requires a utility that owns a nuclear generating plant under Commission jurisdiction to file a site-specific nuclear decommissioning cost study update at least once every five years from the submission date of the previous study unless otherwise required by the Commission. Given that FPL's current study was filed on December 14, 2015, its next study should be filed no later than Monday, December 14, 2020.

Conclusion

FPL's next decommissioning cost study for the Turkey Point Nuclear Generating Station and the St. Lucie Nuclear Power Plant should be filed no later than December 14, 2020.

Issue 7: Should this docket be closed?

Recommendation: If no person whose substantial interests are affected by the Commission's Proposed Agency Action files a protest within 21 days of the issuance of the order, this docket should be closed upon the issuance of a Consummating Order. (Mapp)

Staff Analysis: If no person whose substantial interests are affected by the Commission's Proposed Agency Action files a timely request for hearing within 21 days of the issuance of the order, no further action will be required and this docket should be closed upon the issuance of a consummating order.

Item 11

FILED MAY 26, 2016
DOCUMENT NO. 03214-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

RECEIVED-FPSC
2016 MAY 26 AM 10:06
COMMISSION CLERK

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Guffey) SKG
Office of the General Counsel (Brownless)

RE: Docket No. 160090-EI – Petition for limited extension of experimental large business incentive rate rider, medium business incentive rate rider, and small business incentive rate rider, by Gulf Power Company.

AGENDA: 06/09/16 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 60 Day Suspension Date: June 18, 2016

SPECIAL INSTRUCTIONS: None

Case Background

On April 18, 2016, Gulf Power Company (Gulf or company) filed a petition requesting a limited extension of the company's experimental Large Business Incentive Rate Rider (LBIR), Medium Business Incentive Rate Rider (MBIR), and Small Business Incentive Rate Rider (SBIR), collectively referred to as the riders. The riders were introduced in the Stipulation and Settlement Agreement that the Commission approved during Gulf's 2013 base rate proceeding as a three-year pilot program (January 1, 2014 through December 31, 2016).[1] The riders, which require a five-year electric service contract, provide base rate credits for new businesses that meet certain requirements such as minimum size, job creation, and verification that the availability of the riders are a significant factor in the customer's location or expansion decision.

[1] Order No. PSC-13-0670-S-EI, issued December 19, 2013, in Docket No. 130140-EI, *In Re: Petition for rate increase by Gulf Power Company.*

Staff issued one data request to Gulf on April 26, 2016, for which responses were received on May 10, 2016. After reviewing the responses, staff requested the company's employment verification form referenced in a response which was filed in the docket on May 16, 2016. The tariff pages with proposed changes are contained in Attachment A of this recommendation. The Commission has jurisdiction over this matter pursuant to Sections 288.035 and 366.06, Florida Statutes.

Discussion of Issues

Issue 1: Should the Commission approve Gulf's petition for an extension of its business incentive rate riders until December 31, 2017?

Recommendation: Yes, the Commission should approve Gulf's petition for an extension of its business incentive rate riders until December 31, 2017. (Guffey)

Staff Analysis: The business incentive rate riders are designed to attract new commercial and industrial customers to Gulf's service territory, and foster economic growth. The riders offer base rate electric price incentives over a four-year period for new or expanding businesses that meet certain electric load, and job creation requirements. The LBIR also requires new capital investment of at least $1 million. As shown in Table 1-1, the three riders require that the customers hire and maintain the following number of full-time employees within one year of receiving power service at the qualified delivery point.

Table 1-1
Required Full Time Employees

Riders	kW Load	Number of Full Time Employees
SBIR	200 to 349	10
MBIR	350 to 999	25
LBIR	1,000 kW or greater	25 FTEs per 1,000 kW of qualifying load

Source: Tariff Sheet Nos. 6.93, 6.95, 6.97.

To take service under the riders, the customers must agree to a minimum five-year service agreement and submit documentation verifying the current number of full-time employees. The rider customers are required to annually complete an employment verification form before receiving additional year credits. Table 1-2 illustrates the credits that will be applied to base demand and energy charges.

Table 1-2
Percentage Reduction in Base Demand & Energy Charges

Year	SBIR	MBIR	LBIR
1	20%	40%	60%
2	15%	30%	45%
3	10%	20%	30%
4	5%	10%	15%
5	0%	0%	0%

Source: Tariff Sheet Nos. 6.93, 6.95, 6.97.

Gulf stated in its response to staff discovery that since its approval the program has attracted two retail establishments that started service under the riders in 2015. This new load resulted in approximately $75,735 in incremental base revenue and the addition of 79 employees in Gulf's service territory. The discount amount associated with the new load to date is $9,513.

Gulf explained in its petition that it has received commitments from one new and one expanding customer with a possibility of adding 5,300 new jobs and approximately 4.5 megawatts (MW) of new load. The availability of the riders was a significant factor for the customers' decisions to take service from Gulf. The customers have commenced initial construction work but do not anticipate completion of construction and taking service prior to the expiration of the current riders on December 31, 2016. The company is also actively negotiating with four potential customers to relocate/expand. If successful, Gulf stated they will add over 2,000 jobs and will have a new load demand of 25 MW.

If Gulf's petition is approved, Gulf would make a request to the Commission on or before December 31, 2017 to: (1) continue the riders in their existing form; (2) continue the riders with modifications based on lessons learned; or (3) discontinue the riders in their entirety. Staff notes that the Commission recently approved Tampa Electric Company's petition in Docket No. 160059-EI to extend its economic development rider on a permanent basis. In response to staff inquiry, Gulf explained that the company wishes to continue the pilot program for another year to collect additional information before making a decision on the future of the riders.

The riders appear to be successful in attracting new load and incremental base revenues to Gulf's service territory, which benefits the general body of ratepayers. Therefore, staff recommends that the Commission should approve Gulf's petition for an extension of its business incentive rate riders until December 31, 2017.

Issue 2: Should this docket be closed?

Recommendation: If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff should remain in effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Brownless)

Staff Analysis: If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff should remain in effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
First Revised ~~Original~~ Sheet No. 6.92
Canceling Original Sheet No. 6.92

PAGE	EFFECTIVE DATE
1 of 2	~~January 1, 2014~~

Rate Rider LBIR
Experimental Rate Rider
Large Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

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.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 201~~6~~7 or such earlier date that the Company determines that the subscription limit of 100 MW has been reached for all New Load under this Rider together with the companion Riders, SBIR and MBIR. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider LBIR shall only be combined with Rate Schedules LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.93

PAGE	EFFECTIVE DATE
2 of 2	January 1, 2014

(Continued from Rate Rider LBIR, Sheet No. 6.92)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 60% reduction in base demand and base energy charges
- Year 2 – 45% reduction in base demand and base energy charges
- Year 3 – 30% reduction in base demand and base energy charges
- Year 4 – 15% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 1,000 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 25 full-time employees per 1,000 kW of qualifying load.
(3) The Customer must demonstrate new capital investment of at least $1,000,000.
(4) The Customer must provide an affidavit verifying that the availability of this Rate Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider LBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service.The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
First Revised ~~Original~~ Sheet No. 6.94
Canceling Original Sheet No. 6.94

PAGE	EFFECTIVE DATE
1 of 2	~~January 1, 2014~~

Rate Rider MBIR
Experimental Rate Rider
Medium Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

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.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 20176 or such earlier date that the Company determines that the subscription limit of 100 MW has been reached for all New Load under this Rider together with the companion Riders, SBIR and LBIR. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider MBIR shall only be combined with Rate Schedules GSD, GSDT, GSTOU, LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 8.95

PAGE	EFFECTIVE DATE
2 of 2	January 1, 2014

(Continued from Rate Rider MBIR, Sheet No. 8.94)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 40% reduction in base demand and base energy charges
- Year 2 – 30% reduction in base demand and base energy charges
- Year 3 – 20% reduction in base demand and base energy charges
- Year 4 – 10% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 350 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 25 full-time employees.
(3) The Customer must provide an affidavit verifying that the availability of this Rate Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider MBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service. The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
First Revised ~~Original~~ Sheet No. 6.96
Canceling Original Sheet No. 6.96

PAGE	EFFECTIVE DATE
1 of 2	~~January 1, 2014~~

Rate Rider SBIR
Experimental Rate Rider
Small Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

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.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 20176 or such earlier date that the Company determines that the subscription limit of 100 MW has been reached for all New Load under this Rider together with the companion Riders, MBIR and LBIR. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider SBIR shall only be combined with Rate Schedules GSD, GSDT, GSTOU, LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.97

PAGE	EFFECTIVE DATE
2 of 2	January 1, 2014

(Continued from Rate Rider SBIR, Sheet No. 6.96)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 20% reduction in base demand and base energy charges
- Year 2 – 15% reduction in base demand and base energy charges
- Year 3 – 10% reduction in base demand and base energy charges
- Year 4 – 5% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 200 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 10 full-time employees.
(3) The Customer must provide an affidavit verifying that the availability of this Rate Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider SBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service. The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

Item 12

FILED MAY 26, 2016
DOCUMENT NO. 03215-16
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Bruce, Hudson)
Division of Accounting and Finance (T. Brown, D. Buys)
Division of Engineering (Hill)
Office of the General Counsel (Mapp)

ALM

RE: Docket No. 160030-WS – Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.

AGENDA: 06/09/16 – Regular Agenda – Decision on Suspension of Rates and Interim Rates – Participation is at the Discretion of the Commission

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: (60-Day Suspension and Interim Date waived until 06/09/16)

SPECIAL INSTRUCTIONS: None

Case Background

Ni Florida, LLC (Ni Florida or utility) is a Class A utility serving approximately 743 water connections in Lee County and 2,749 wastewater connections in Pasco County. Water and wastewater rates were last established for the utility in 2013.[1] On April 4, 2016, Ni Florida filed its application for the rate increase at issue in the instant docket.

On May 3, 2016, staff sent the utility a letter indicating deficiencies in the filing of its minimum filing requirements (MFRs). On May 13, 2016, the utility provided corrections to the MFRs and

[1]Order No. PSC-13-0611-PAA-WS, issued November 19, 2013, in Docket No. 130010-WS, *In re: Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.*

staff determined that the MFRs are complete. Therefore, the official filing date is May 13, 2016. The utility requested that the application be processed using the Proposed Agency Action (PAA) procedure and requested interim rates. The test year established for interim and final rates is based on a 13 month average for the period ended December 31, 2015. Ni Florida requested interim revenue increases of $75,950 (32.3 percent) for water and $432,000 (22.4 percent) for wastewater. The utility requested final revenue increases of $87,150 (37.1 percent) for water and $475,000 (24.6 percent) for wastewater.

The 60-day statutory deadline for the Commission to suspend the utility's requested final rates and approve interim rates is June 4, 2016. However, by letter dated April 11, 2016, the utility agreed to extend the time by which the Commission is required to suspend the proposed rates and authorize interim rates through the June 9, 2016 Commission Conference. This recommendation addresses the suspension of Ni Florida's requested final rates and its requested interim rates. The Commission has jurisdiction pursuant to Sections 367.081 and 367.082, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the utility's proposed final water and wastewater rates be suspended?

Recommendation: Yes. Ni Florida's proposed final water and wastewater rates should be suspended. (Bruce)

Staff Analysis: Section 367.081(6), F.S., provides that the Commission may, for good cause, withhold consent to the implementation of requested rates within 60 days after the date the rate request is filed. Further, Section 367.081(8), F.S., permits the proposed rates to go into effect (secured and subject to refund) at the expiration of five months from the official date of filing if: (1) the Commission has not acted upon the requested rate increase; or (2) if the Commission's PAA action is protested by a party other than the utility.

Staff reviewed the filing and considered the information filed in support of the rate application and the proposed final rates. Staff believes that further investigation of this information, including on-site inspections, is needed. Staff initiated an audit of Ni Florida's books and records, as well as an audit of the utility's proposed allocation of parent company investment and operating expenses. Both of these audits are tentatively due on July 29, 2016. In addition, staff sent its first data request to the utility on May 26, 2016. The utility's response to the data request is due on June 14, 2016. Based on the foregoing, staff recommends Ni Florida's proposed final water and wastewater rates be suspended.

Issue 2: Should any interim revenue increase be approved?

Recommendation: Yes, Ni Florida should be authorized to collect annual water and wastewater revenues as indicated below:

	Adjusted Test Year Revenues	$ Increase	Revenue Requirement	% Increase
Water	$223,689	$87,202	$310,891	38.98%
Wastewater	$1,932,151	$332,619	$2,264,770	17.21%

(T. Brown, Hill)

Staff Analysis: On April 4, 2016, Ni Florida filed its rate base, cost of capital, and operating statements to support its requested interim increase in water and wastewater rates. Pursuant to Section 367.082(1), F.S., in order to establish a prima facie entitlement for interim relief, the utility shall demonstrate that it is earning outside the range of reasonableness on its rate of return. Pursuant to Section 367.081(2)(a), F.S., in a proceeding for an interim increase in rates, the Commission shall authorize, within 60 days of the filing for such relief, the collection of rates sufficient to earn the minimum of the range of rate of return. Based on the utility's filing and the recommended adjustments below, staff believes that the utility has demonstrated a prima facie entitlement in accordance with Section 367.082(1), F.S.

Pursuant to Section 367.082(5)(b)1, F.S., the achieved rate of return for interim purposes must be calculated by applying adjustments consistent with adjustments made in the utility's most recent rate proceeding and annualizing any rate changes. Staff has reviewed Ni Florida's interim request, as well as Order No. PSC-13-0611-PAA-WS, in which the Commission last established rate base.[2] Staff's recommended adjustments are discussed below. Staff has attached accounting schedules to illustrate staff's recommended rate base, capital structure, and test year operating income amounts. Rate base schedules are labeled as Schedule Nos. 1-A and 1-B, with the adjustments shown on Schedule No. 1-C. Capital structure is labeled as Schedule No. 2. Operating income schedules for water and wastewater, respectively, are labeled as Schedule Nos. 3-A and 3-B, with the adjustments shown on Schedule No. 3-C.

Rate Base

Pursuant to Section 367.082(5)(b)1., F.S., the achieved rate of return for interim purposes must be calculated by applying adjustments consistent with adjustments made in the utility's most recent rate proceeding. Based on staff's review, there are several adjustments necessary for interim purposes.

Based on staff's review, adjustments are necessary to remove amounts from the wastewater plant in service balance associated with the utility's pro forma plant projects of $812,142 ($82,880 + $729,262) and plant retirements of $545,254. Those adjustments net to a $266,889 ($812,142 – $545,254) reduction for wastewater only. No pro forma plant projects were included for water. A

[2] Id.

corresponding adjustment is necessary to increase accumulated depreciation for wastewater by $545,254.

Ni Florida also included pro forma deferred income taxes of $2,173 and $100,742 for water and wastewater respectively. Staff removed the utility's pro forma deferred income tax adjustments in totality.

In its filing, the utility used the balance sheet approach to calculate interim working capital, which is appropriate for a Class A utility. The calculated total company working capital was $282,538, and it was allocated to each of Ni Florida's systems based on Equivalent Residential Connections (ERCs) as of December 31, 2015.

The utility included $60,448 in its working capital calculation for deferred rate case expense. In Ni Florida's last rate case, the Commission approved total rate case expense of $149,321.[3] Consistent with the Utility's last rate case and Commission practice, one-half of the total rate case expense shall be included in working capital. Staff believes that one-half of the prior Commission-approved rate case expense, or $74,661, is the appropriate amount of deferred rate case expense to be included in working capital for interim purposes. As such, deferred rate case expense should be increased by $14,213 ($74,661 - $60,448). Staff increased working capital by $2,738 for water and $11,475 for wastewater. The increase results in a working capital allowance of $296,751.

Pursuant to Section 367.082, F.S., the method used to calculate Used and Useful (U&U) in Ni Florida's last rate case must be used for interim purposes. By Order No. PSC-13-0611-PAA-WS, the Commission found that Ni Florida's water and wastewater systems were 100 percent U&U. Therefore, no U&U adjustments are necessary for interim purposes.

Based on the above, staff recommends that Ni Florida's interim water rate base should be $332,657 and wastewater rate base should be $3,178,663.

Cost of Capital

Based on an analysis of the MFRs and staff's review of Order No. PSC-13-0611-PAA-WS from the utility's last rate proceeding, staff believes adjustments are necessary to the utility's capital structure. In its interim request, the utility used a return on equity (ROE) of 9.27 percent. However, the minimum of the range of its last authorized ROE was 8.42 percent. The utility also included $102,915 of deferred income taxes in its capital structure. This amount is consistent with the amount of pro forma deferred income taxes the utility included in its requested interim rate base. Consistent with the removal of pro forma deferred income taxes discussed previously, staff believes deferred income taxes should be removed from the utility's interim cost of capital. With these adjustments, staff recommends an interim weighted average cost of capital for Ni Florida of 7.52 percent.

Net Operating Income

In order to attain the appropriate amount of interim test year operating revenues, staff removed the utility's requested interim revenue increase of $75,950 for water and $432,000 for

[3]Order No. PSC-13-0611-PAA-WS, p.20.

wastewater. Based on staff's annualized revenue calculations, water revenues should be reduced by $11,252 and wastewater revenues increased by $2,413.

Based on staff's review, several adjustments to operation and maintenance (O&M) expenses are necessary for interim purposes. Pursuant to Section 367.082(5)(b)l., F.S., the only adjustments that should be made to the interim test year are those consistent with the most recent individual rate proceeding or adjustments to annualize rate changes occurring during the interim test year. As such, staff believes that the utility's adjustments to bad debt expense based on a percentage of the proposed revenue increase are pro forma in nature and should be removed. Staff reduced bad debt expense by $367 for water and $5,978 for wastewater.

Staff made an adjustment to correct an error made in calculating the allocable portion of miscellaneous expense in MFR Schedule B-12. The utility calculated that Ni Florida's portion of allocable miscellaneous expenses was $367,338. Staff calculated Ni Florida's portion of allocable miscellaneous expenses to be $367,138. Staff reduced allocable miscellaneous expense by $200, which resulted in a $45 reduction to water and a $155 reduction to wastewater.

In the last rate case, the Commission also made adjustments to the utility's director and officer liability (DOL) insurance, due diligence costs, and equity sponsor fee. According to the utility, due diligence costs and the equity sponsor fee were excluded from allocable expenses during the preparation of the rate filing. As such, no adjustments are necessary for due diligence or the equity sponsor fee. However, the utility's parent company recorded DOL insurance expense of $47,862 for the test year. Consistent with the methodology used in the last rate case,[4] DOL insurance costs prior to any allocation should be reduced by $23,931 ($47,862 divided by 2). Based on the above, Ni Florida's allocated expenses should be $2,058 ($23,931 multiplied by Ni Florida's 8.60 percent allocation factor), or $425 for water and $1,633 for wastewater. The utility included $851 for water and $3,267 for wastewater in the current test year. Based on staff's calculations, DOL insurance should be reduced by $426 ($425 - $851) and $1,634 ($1,633 - $3,267) for water and wastewater, respectively.

Staff also removed the utility's depreciation expense adjustments related to year-end plant in service and changes in depreciation due to wastewater plant replacements. The resulting adjustments totaled $817 and $18,132 for water and wastewater, respectively.

Finally, staff made adjustments to taxes other than income (TOTI) to reflect the revenue and O&M expense adjustments cited above. Staff reduced regulatory assessment fees (RAFs) by $3,924 for water and $19,331 for wastewater to reflect the removal of the utility's requested revenue increase. Staff also removed the utility's wastewater property tax adjustment of $4,564 for pro forma plant projects.

Based on the above, staff recommends that the appropriate test year operating income, before any revenue increase, is a $27,366 loss for water and income of $40,818 for wastewater.

[4]Order No. PSC-13-0611-PAA-WS, p.17.

Revenue Requirement

Based on the above adjustments, allowing the utility to earn a 7.52 percent return on its water rate base would result in a revenue requirement of $311,615. The utility has requested an interim revenue requirement of $310,891. In such circumstances, it has been Commission practice to limit the revenue requirement to the level requested by the utility. Consistent with Commission practice,[5] staff recommends a revenue requirement of $310,891 for water. This represents an interim increase in annual revenues of $87,202 (or 38.98 percent). This will allow the utility the opportunity to recover its water operating expenses and earn a 7.39 percent return on its water rate base.

Staff recommends a wastewater revenue requirement of $2,264,770. This represents an increase in annual revenues of $332,619 (or 17.21 percent) for wastewater. The increase will allow the utility the opportunity to recover its wastewater operating expenses and earn a 7.52 percent return on its wastewater rate base.

[5]Order Nos. PSC-13-0673-FOF-WS, issued December 19, 2013, in Docket No. 130212-WS, *In re: Application for increase in water/wastewater rates in Polk County by Cypress Lakes Utilities, Inc.*; PSC-10-0018-PCO-WS, issued January 6, 2010, in Docket No. 090402-WS, *In re: Application for increase in water and wastewater rates in Seminole County by Sanlando Utilities Corporation*; PSC-06-0675-PCO-SU, issued August 7, 2006, in Docket No. 060255-SU, *In re: Application for increase in wastewater rates in Pinellas County by Tierra Verde Utilities, Inc.*; PSC-05-0287-PAA-SU, issued March 17, 2005, in Docket No. 040972-SU, *In re: Application for rate increase in Pinellas County by Ranch Mobile WWTP, Inc.*; and PSC-95-0191-FOF-WS, issued February 9, 1995, in Docket No. 940917-WS, *In re: Application for rate increase for increased water and wastewater rates in Seminole, Orange, and Pasco Counties by Utilities, Inc. of Florida.*

Issue 3: What are the appropriate interim water and wastewater rates?

Recommendation: The recommended interim rate increase of 40.12 percent for water and 17.71 percent for wastewater should be applied as an across-the-board increase to the existing service rates. The rates, as shown on Schedule Nos. 4-A and 4-B, should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. The utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. In addition, the approved rates should not be implemented until the required security has been filed, staff has approved the proposed customer notice, and the notice has been received by the customers. The utility should provide proof of the date notice was given within 10 days of the date of the notice. (Bruce)

Staff Analysis: Staff recommends that interim service rates for Ni Florida be designed to allow the utility the opportunity to generate annual operating revenues of $310,891 and $2,264,770 for water and wastewater, respectively. Before removal of miscellaneous revenues, this would result in an increase of $87,202 (38.98 percent) for water and $332,619 (17.21 percent) for wastewater. To determine the appropriate increase to apply to the service rates, miscellaneous revenues should be removed from the test year revenues. The calculation is as follows:

Table 3
Percentage Service Rate Increase

		Water	Wastewater
1	Total Test Year Revenues	$223,689	$1,932,151
2	Less: Miscellaneous Revenues	$6,357	$53,756
3	Test Year Revenues from Service Rates	$217,332	$1,878,395
4	Revenue Increase	$87,202	$332,619
5	Percentage Service Rate Increase (Line 4/Line 3)	40.12%	17.71%

Source: Staff's Recommended Revenue Requirement and MFRs

Staff recommends that the interim rate increases of 40.12 percent for water and 17.71 percent for wastewater should be applied as an across-the-board increase to the existing service rates. The rates, as shown on Schedule Nos. 4-A and 4-B, should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. The utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. In addition, the approved rates should not be implemented until the required security has been filed, staff has approved the proposed customer notice, and the notice has been received by the customers. The utility should provide proof of the date notice was given within 10 days of the date of the notice.

Issue 4: What is the appropriate security to guarantee the interim increase?

Recommendation: The utility should be required to secure a letter of credit, or alternately an escrow account or surety bond, to guarantee any potential refund of revenues collected under interim conditions. If the security provided is a letter of credit or surety bond, it should be in the amount of $245,203. Otherwise, the utility should deposit $34,985 into the escrow account each month. Pursuant to Rule 25-30.360(6), F.A.C., the utility should provide a report by the 20th of each month indicating the monthly and total revenue collected subject to refund. Should a refund be required, the refund should be with interest and in accordance with Rule 25-30.360, F.A.C. (D. Buys, T. Brown)

Staff Analysis: Pursuant to Section 367.082, F.S., revenues collected under interim rates shall be placed under bond, escrow, letter of credit, or corporate undertaking subject to refund with interest at a rate ordered by the Commission. As recommended in Issue 2, the total interim increase is $419,821. In accordance with Rule 25-30.360, F.A.C., staff calculated the potential refund of revenues and interest collected under interim conditions to be $245,203. This amount is based on an estimated seven months of revenue being collected from staff's recommended interim rates over the utility's current authorized rates shown on Schedule Nos. 4-A and 4-B.

The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. The utility has indicated to staff that it intends to utilize a letter of credit as security for any potential refund of interim rates granted. As such, staff did not perform an analysis regarding the utility's financial capability to support a corporate undertaking. Staff recommends Ni Florida be required to secure a letter of credit, or alternately an escrow account or surety bond, to guarantee any potential refund of water and wastewater revenues. The requirements associated with each are discussed below.

If the security provided is a surety bond or a letter of credit, said instrument should be in the amount of $245,203. If the utility chooses a surety bond as security, the surety bond should state that it will be released or terminated only upon subsequent order of the Commission. If the utility chooses to provide a letter of credit as security, the letter of credit should state that it is irrevocable for the period it is in effect and that it will be in effect until a final Commission order is rendered releasing the funds to the utility or requiring a refund.

If the security provided is an escrow account, said account should be established between the utility and an independent financial institution or the Division of Treasury for the Florida Department of Financial Services pursuant to a written escrow agreement. The Commission should be a party to the written escrow agreement and a signatory to the escrow account. The written escrow agreement should state the following: the account is established at the direction of the Commission for the purpose set forth above; no withdrawals of funds shall occur without the prior approval of the Commission through the Commission Clerk, Office of Commission Clerk; the account shall be interest bearing; information concerning that escrow account shall be available from the institution to the Commission or its representative at all times; the amount of revenue subject to refund shall be deposited in the escrow account within seven days of receipt; and, pursuant to Cosentino v. Elson, 263 So. 2d 253 (Fla 3d DCA 1972), escrow accounts are not subject to garnishments.

If the security provided is an escrow account, the utility should deposit $34,985 into the escrow account each month. The escrow agreement should also state that "if a refund to the customers is required, all interest earned on the escrow account shall be distributed to the customers, and if a refund to the customers is not required, the interest earned on the escrow account shall revert to the utility."

Regardless of the type of security provided, the utility should keep an accurate and detailed account of all monies it receives. Pursuant to Rule 25-30.360(6), F.A.C., the utility should provide a report by the 20th day of each month indicating the monthly and total revenue collected subject to refund. Should a refund be required, the refund should be with interest and undertaken in accordance with Rule 25-30.360, F.A.C.

In no instance should maintenance and administrative costs associated with any refund be borne by the customers. Such costs are the responsibility of, and should be borne by, the utility.

Issue 5: Should this docket be closed?

Recommendation: The docket should remain open pending the Commission's PAA decision on the utility's requested rate increase. (Mapp)

Staff Analysis: The docket should remain open pending the Commission's PAA decision on the utility's requested rate increase.

Ni Florida, LLC
Schedule of Water Rate Base
Test Year Ended 12/31/15

Schedule No. 1-A
Docket No. 160030-WS

	Description	Test Year Per Utility	Utility Adjust-Ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$568,878	$0	$568,878	$0	$568,878
2	Accumulated Depreciation	(303,287)	0	(303,287)	0	(303,287)
3	CIAC	(110,779)	0	(110,779)	0	(110,779)
4	Amortization of CIAC	110,779	0	110,779	0	110,779
5	Acquisition Adjustments	1,047,160	(1,047,160)	0	0	0
6	Accumulated Deferred Income Taxes	0	(2,173)	(2,173)	2,173	0
7	Working Capital Allowance	64,328	0	64,328	2,738	67,066
8	Rate Base	$1,377,079	($1,049,333)	$327,746	$4,911	$332,657

Ni Florida, LLC
Schedule of Wastewater Rate Base
Test Year Ended 12/31/15

Schedule No. 1-B
Docket No. 160030-WS

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$9,155,410	$266,889	$9,422,299	($266,889)	$9,155,410
2	Land and Land Rights	9,513	0	9,513	0	9,513
3	Accumulated Depreciation	(4,520,375)	545,254	(3,975,121)	(545,254)	(4,520,375)
4	CIAC	(3,638,516)	0	(3,638,516)	0	(3,638,516)
5	Amortization of CIAC	1,946,580	0	1,946,580	0	1,946,580
6	Construction Work in Progress	479,348	(479,348)	0	0	0
7	Acquisition Adjustments	5,726,865	(5,726,865)	0	0	0
8	Accumulated Deferred Income Taxes	(3,634)	(100,742)	(104,376)	100,742	(3,634)
9	Working Capital Allowance	218,210	0	218,210	11,475	229,685
10	Rate Base	$9,373,401	($5,494,812)	$3,878,589	($699,926)	$3,178,663

Ni Florida, LLC Adjustments to Rate Base Test Year Ended 12/31/15		**Schedule No. 1-C Docket No. 160030-WS**
Explanation	**Water**	**Wastewater**
Plant In Service		
Remove pro forma plant and retirement adjustments. (Issue 2)	$0	($266,889)
Accumulated Depreciation		
Remove pro forma plant and retirement adjustments. (Issue 2)	$0	($545,254)
Accumulated Deferred Income Taxes		
Remove adjustment for pro forma deferred income taxes. (Issue 2)	$2,173	$100,742
Working Capital		
Reflect appropriate Deferred rate case expense. (Issue 2)	$2,738	$11,475

Ni Florida, LLC
Capital Structure-Simple Average
Test Year Ended 12/31/15

Schedule No. 2
Docket No. 160030-WS

	Description	Total Capital	Specific Adjust-ments	Subtotal Adjusted Capital	Prorata Adjust-ments	Capital Reconciled to Rate Base	Ratio	Cost Rate	Weighted Cost
Per Utility									
1	Long-term Debt - Fixed Rate	47,595	0	47,595	0	47,595	1.13%	8.50%	0.10%
2	Long-term Debt - Variable Rate	878,720	0	878,720	0	878,720	20.90%	4.50%	0.94%
3	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
4	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
5	Common Equity	3,086,892	0	3,086,892	0	3,086,892	73.41%	9.27%	6.81%
6	Customer Deposits	85,202	0	85,202	0	85,202	2.03%	6.00%	0.12%
7	Deferred Income Taxes	3,634	102,915	106,549	0	106,549	2.53%	0.00%	0.00%
8	**Total Capital**	$4,102,043	$102,915	$4,204,958	$0	$4,204,958	100.00%		7.97%
Per Staff									
9	Long-term Debt- Fixed Rate	47,595	0	47,595	(7,006)	40,589	1.16%	8.50%	0.10%
10	Long-term Debt - Variable Rate	878,720	0	878,720	(129,343)	749,377	21.34%	4.50%	0.96%
11	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
12	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
13	Common Equity	3,086,892	0	3,086,892	(454,374)	2,632,518	74.97%	8.42%	6.31%
14	Customer Deposits	85,202	0	85,202	0	85,202	2.43%	6.00%	0.15%
15	Deferred Income Taxes	3,634	0	3,634	0	3,634	0.10%	0.00%	0.00%
16	**Total Capital**	$4,102,043	$0	$4,102,043	($590,723)	$3,511,320	100.00%		7.52%

	LOW	HIGH
RETURN ON EQUITY	8.42%	10.42%
OVERALL RATE OF RETURN	7.52%	9.02%

Ni Florida, LLC
Statement of Water Operations
Test Year Ended 12/31/15

Schedule No. 3-A
Docket No. 160030-WS

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues:**	$243,169	$67,722	$310,891	($87,202)	$223,689	$87,202	$310,891
							38.98%	
	Operating Expenses							
2	Operation & Maintenance	$238,510	$433	$238,943	($837)	$238,106	$0	$238,106
3	Depreciation	19,513	817	20,330	(817)	19,513	0	19,513
4	Amortization	0	0	0	0	0	0	0
5	Taxes Other Than Income	10,943	3,418	14,361	(3,924)	10,437	3,924	14,361
6	Income Taxes	0	12,220	12,220	(29,220)	(17,000)	31,337	14,337
7	**Total Operating Expense**	$268,966	$16,888	$285,854	($34,799)	$251,055	$35,262	$286,317
8	**Operating Income**	($25,797)	$50,834	$25,037	($52,403)	($27,366)	$51,940	$24,574
9	**Rate Base**	$1,377,079		$327,746		$332,657		$332,657
10	**Rate of Return**	-1.87%		7.64%		-8.23%		7.39%

Ni Florida, LLC
Statement of Wastewater Operations
Test Year Ended 12/31/15

Schedule No. 3-B
Docket No. 160030-WS

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues:**	$1,929,738	$432,000	$2,361,738	($429,587)	$1,932,151	$332,619	$2,264,770
							17.21%	
	Operating Expenses							
2	Operation & Maintenance	1,515,833	32,683	1,548,516	(7,768)	1,540,748	0	1,540,748
3	Depreciation	166,265	18,132	184,397	(18,132)	166,265	0	166,265
4	Amortization	0	0	0	0	0	0	0
5	Taxes Other Than Income	164,261	24,004	188,265	(23,895)	164,370	14,968	179,337
6	Income Taxes	47,244	97,048	144,292	(124,342)	19,950	119,532	139,482
7	**Total Operating Expense**	$1,893,603	$171,867	$2,065,470	($174,137)	$1,891,333	$134,500	$2,025,833
8	**Operating Income**	$36,135	$260,133	$296,268	($255,450)	$40,818	$198,119	$238,937
9	**Rate Base**	$9,373,401		$3,878,589		$3,178,663		$3,178,663
10	**Rate of Return**	0.39%		7.64%		1.28%		7.52%

Ni Florida, LLC
Adjustment to Operating Income
Test Year Ended 12/31/15

Schedule 3-C
Docket No. 160030-WS

	Explanation	Water	Wastewater
	Operating Revenues		
1	Remove requested interim revenue increase. (Issue 2)	($75,950)	($432,000)
2	Reflect the appropriate amount of test year revenues. (Issue 2)	(11,252)	2,413
	Total	($87,202)	($429,587)
	Operation and Maintenance Expense		
1	Remove utility's pro forma bad debt expense adjustments. (Issue 2)	($367)	($5,978)
2	Correction to allocable portion of miscellaneous expenses. (Issue 2)	(45)	(155)
3	Reflect appropriate amount of miscellaneous expense. (Issue 2)	(426)	(1,634)
	Total	($837)	($7,768)
	Depreciation Expense – Net		
	Remove adjustments for change in depreciation. (Issue 2)	($817)	($18,132)
	Taxes Other Than Income		
1	RAFs on revenue adjustments above. (Issue 2)	($3,924)	($19,331)
2	Remove property tax adjustment for pro forma plant projects. (Issue 2)	0	(4,564)
	Total	($3,924)	($23,895)

Ni Florida, LLC. | **Schedule No. 4-A**
Test Year Ended 12/31/2015 | **Docket No. 160030-WS**
Monthly Water Rates

	Current Rates	Utility Requested Interim	Utility Requested Final	Staff Recommended Interim
Residential and General Service				
Base Facility Charge by Meter Size				
5/8 x 3/4"	$12.64	$17.70	$18.34	$17.71
3/4"	$18.96	$26.54	$27.52	$26.57
1"	$31.60	$44.24	$45.86	$44.28
1-1/2"	$63.21	$88.49	$91.73	$88.55
2"	$101.13	$141.57	$146.76	$141.68
3"	$202.27	$312.69	$324.15	$283.36
4"	$316.04	$442.43	$458.65	$442.75
6"	$632.08	$884.86	$917.29	$885.50
8"	$1,011.20	$1,415.60	$1,467.48	$1,416.80
RV Park	$1,324.36	$1,854.00	$1,921.95	$1,855.69
Charge per 1,000 Gallons - Residential Service				
0-3,000 gallons	$4.47	$6.26	$6.49	$6.26
3,001-6,000 gallons	$5.66	$7.92	$8.21	$7.93
Over 6,000 gallons	$7.88	$11.03	$11.44	$11.04
Charge per 1,000 Gallons - General Service	$4.81	$6.73	$6.98	$6.74
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$26.05	$36.48	$37.81	$36.49
6,000 Gallons	$43.03	$60.24	$62.44	$60.28
8,000 Gallons	$58.79	$82.30	$85.32	$82.36

Ni Florida, LLC.
Test Year Ended 12/31/2015
Monthly Wastewater Rates

Schedule No. 4-B
Docket No. 160030-WS

	Current Rates	Utility Requested Interim	Utility Requested Final	Staff Recommended Interim
Residential Service				
Base Facility Charge - All Meter Sizes	$20.95	$25.63	$26.11	$24.66
Charge per 1,000 Gallons- Residential	$6.87	$8.40	$8.56	$8.09
8,000 gallon cap				
General Service				
Base Facility Charge by Meter Size				
5/8 x 3/4"	$20.95	$25.63	$26.11	$24.66
3/4"	$31.43	$38.45	$39.17	$36.99
1"	$52.38	$64.08	$65.28	$61.65
1-1/2"	$105.46	$129.01	$131.43	$123.30
2"	$167.64	$205.08	$208.92	$197.28
3"	$335.27	$410.14	$417.82	$394.56
4"	$523.86	$640.85	$652.84	$616.50
6"	$1,047.73	$1,281.71	$1,305.70	$1,233.00
8"	$1,676.37	$2,050.74	$2,089.12	$1,972.80
10"	$2,409.78	$2,947.94	$3,003.10	$2,835.90
Bulk Service	$523.86	$640.85	$652.84	$616.50
Charge per 1,000 Gallons - General Service	$8.24	$10.08	$10.27	$9.70
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$41.56	$50.83	$51.79	$48.93
6,000 Gallons	$62.17	$76.03	$77.47	$73.20
8,000 Gallons	$75.91	$92.83	$94.59	$89.38

Item 13

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 26, 2016

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Johnson, Hudson)
Office of the General Counsel (Leathers)

RE: Docket No. 160104-WS – Application for NSF and late payment charges in Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties by Utilities Inc. of Florida.

AGENDA: 06/09/16 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 06/20/16 (60-day suspension date)

SPECIAL INSTRUCTIONS: None

Case Background

Utilities, Inc. of Florida (UIF or utility) is a Class A water and wastewater utility serving approximately 33,193 water and 26,450 wastewater utility customers in Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties.

Following the consolidation of the utility's systems in Docket No. 150235-WS, the utility requested a revision of its non-sufficient funds (NSF) charges and late payment charges so that the charges would be consistent across all systems. On April 20, 2016, UIF filed an application for approval of NSF charges and late payment charges for those systems in Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties that do not currently have those approved charges. UIF currently has only two systems, formerly known as Lake Placid Utilities, Inc. and Cypress Lakes Utilities, Inc., that have an approved late payment charge. Additionally, UIF has only three systems, formerly known as Utilities, Inc. of

Sandalhaven, Tierra Verde Utilities, Inc., and Utilities, Inc. of Eagle Ridge, that do not have an approved NSF charge. This recommendation addresses UIF's request for approval of a late payment charge and NSF charges. The Commission has jurisdiction to consider this matter pursuant to Section 367.091(6), Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should UIF's current late payment charge of $5.25 be applied to all of UIF's systems?

Recommendation: Yes. UIF's request to uniformly implement a late payment charge of $5.25 should be approved. UIF should be required to file a proposed customer notice to reflect the Commission-approved charge for those systems where the charge is not currently approved. The approved charge should be effective for services rendered on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), Florida Administrative Code (F.A.C.). In addition, the approved charge should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date notice was given no less than ten days after the date of the notice. (Johnson)

Staff Analysis: Section 367.091(6), F.S., authorizes the Commission to establish, increase, or change a rate or charge other than monthly rates or service availability charges. The utility is requesting a $5.25 late payment charge for those systems that do not currently have an approved late payment charge to recover the cost of supplies and labor associated with processing late payment notices. The utility's request for a late payment charge was accompanied by its reason for requesting the charge, as well as the cost justification required by Section 367.091(6), F.S.

Approximately 1.61 percent or 960 (1.61% x 59,642) of UIF's bills are delinquent on a monthly basis. The utility's requested charge is based on an aggregate of all UIF systems. The utility indicated that it processes six late payment charges an hour. UIF's combined employees' salary is $44.68 per hour and at six transactions an hour results in a labor cost of $7.45 ($44.68/6). UIF provided a cost justification for a late payment charge of $8.14. The cost basis for the late payment charge, including labor, is shown below.

Table 1-1
Cost Basis for Late Payment Charge

Labor	$7.45
Printing	0.20
Postage	0.49
Total	$8.14

For administrative efficiency, the utility would like to have a unified late payment charge for all UIF systems. Therefore, the utility is only requesting a charge of $5.25, which is the previously approved charge for two UIF systems, formerly known as Lake Placid Utilities, Inc. and Cypress Lakes Utilities, Inc.[1] Staff believes the cost justification provided by the utility indicates that the requested late payment charge of $5.25 for the remaining UIF systems is reasonable.

[1] See Order Nos. PSC-14-0335-PAA-WS, in Docket No. 130243-WS, issued June 30, 2014, *In re: Application for staff-assisted rate case in Highlands County by Lake Placid Utilities Inc.*; PSC-14-0283-PAA-WS, in Docket No. 130212-WS, issued May 30, 2014, *In re: Application for increase in water/wastewater rates in Polk County by Cypress Lakes Utilities, Inc.*

Based on staff's research, since the late 1990s, the Commission has approved late payment charges ranging from \$2.00 to \$7.00.[2] The purpose of this charge is not only to provide an incentive for customers to make timely payment, thereby reducing the number of delinquent accounts, but also to place the cost burden of processing delinquent accounts solely upon those who are cost causers.

Based on the above, staff recommends that UIF's request to implement a uniform late payment charge of \$5.25 be approved. UIF should be required to file a proposed customer notice to reflect the Commission-approved charge for those systems where the charge is not currently approved. The approved charge should be effective for services rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved charge should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date notice was given no less than ten days after the date of the notice.

[2] See Order Nos. PSC-14-0335-PAA-WS, in Docket No. 130243-WS, issued June 30, 2014, *In re: Application for staff-assisted rate case in Highlands County by Lake Placid Utilities Inc.*; PSC-14-0105-TRF-WS, in Docket No. 130288-WS, issued February 20, 2014, *In re: Request for approval of late payment charge in Brevard County by Aquarina Utilities, Inc.*; PSC-13-0177-PAA-WU, in Docket No. 130052-WU, issued April 29, 2013, *In re: Application for grandfather certificate to operate water utility in Charlotte County by Little Gasparilla Water Utility, Inc.*; PSC-10-0257-TRF-WU, in Docket No. 090429-WU, issued April 26, 2010, *In re: Request for approval of imposition of miscellaneous service charges, delinquent payment charge and meter tampering charge in Lake County, by Pine Harbour Water Utilities, LLC.*; and PSC-11-0204-TRF-SU, in Docket No. 100413-SU, issued April 25, 2011, *In re: Request for approval of tariff amendment to include a late fee of \$14.00 in Polk County by West Lakeland Wastewater.*

Issue 2: Should UIF's current NSF charge be applied to all of UIF's systems?

Recommendation: Yes. UIF's request to uniformly implement a NSF charge should be approved. Staff recommends that UIF revise its tariffs to reflect the NSF charges currently set forth in Section 68.065, F.S. UIF should be required to file a proposed customer notice to reflect the Commission-approved charge for those systems where the charge is not currently approved. The NSF charges should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. Furthermore, the charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice. (Johnson)

Staff Analysis: Section 367.091, F.S., requires rates, charges, and customer service policies to be approved by the Commission. The Commission has authority to establish, increase, or change a rate or charge.

Three of UIF's wastewater systems, formerly known as Utilities, Inc. of Sandalhaven, Tierra Verde Utilities, Inc., and Utilities, Inc. of Eagle Ridge, do not currently have an approved NSF charge. Staff believes that UIF should be authorized to collect NSF charges consistent with Section 68.065, F.S., which allows for the assessment of charges for the collection of worthless checks, drafts, or orders of payment. As currently set forth in Section 68.065(2), F.S., the following NSF charges may be assessed:

(1) $25, if the face value does not exceed $50,

(2) $30, if the face value exceeds $50 but does not exceed $300,

(3) $40, if the face value exceeds $300,

(4) or five percent of the face amount of the check, whichever is greater.

Approval of NSF charges is consistent with prior Commission decisions.[3] Furthermore, NSF charges place the cost on the cost-causer, rather than requiring that the costs associated with the return of the NSF checks be spread across the general body of ratepayers. As such, UIF should be authorized to collect NSF charges for all systems. Staff recommends that UIF revise its tariff sheet to reflect the NSF charges currently set forth in Section 68.065, F.S. UIF should be required to file a proposed customer notice to reflect the Commission-approved charge for those systems where the charge is not currently approved. The NSF charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. Furthermore, the NSF charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice.

[3]Order Nos. PSC-14-0198-TRF-SU, issued May 2, 2014, in Docket No. 140030-SU, *In re: Request for approval to amend Miscellaneous Service charges to include all NSF charges by Environmental Protection Systems of Pine Island, Inc.;* and PSC-13-0646-PAA-WU, issued December 5, 2013, in Docket No. 130025-WU, *In re: Application for increase in water rates in Highlands County by Placid Lakes Utilities, Inc.*

Issue 3: Should this docket be closed?

Recommendation: If Issue 1 and 2 are approved, the docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the utility and approved by staff. If a protest is filed within 21 days of the issuance date of the Order, the tariff sheets should remain in effect with all charges held subject to refund pending resolution of the protest. If no timely protest is filed, a consummating order should be issued and, once staff verifies that the notice of the charges has been given to customers, the docket should be administratively closed. (Johnson, Leathers)

Staff Analysis: If Issue 1 and 2 are approved, the docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the utility and approved by staff. If a protest is filed within 21 days of the issuance date of the Order, the tariff sheets should remain in effect with all charges held subject to refund pending resolution of the protest. If no timely protest is filed, a consummating order should be issued and, once staff verifies that the notice of the charges has been given to customers, the docket should be administratively closed.